THE FUTURE PRICES OF ELECTRICITY IN MONTANA

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1. SUMMARY AND CONCLUSIONS

1.1 Scope and Purpose of the Analysis

This study provides a projection of the average prices of electricity for much of the state of Montana. Given limited resources, we have chosen to concentrate the analysis on the Montana Power Company (MPCo) and the Bonneville Power Administration (BPA). In 1974, the Montana Power Company provided 84.6% of the sales of electricity to ultimate consumers by privately-owned utilities in the state of Montana. However, nearly 45% of the total 9.5 billion kilowatt hours sold in the state are provided by publicly-owned utilities. The rates for public power, largely dominated by BPA, are analyzed in Section 4 below. A detailed model and a great deal of empirical data for the MPCo is summarized in Section 3.

The purpose of the analysis is to provide decision-makers in government and industry with a reliable forecast of future prices. We are also concerned with identifying the effect on rates of changes in specific factors, such as fuel prices. The study is funded by the Montana Department of Administration and coordinated

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[1]Derived FPC Form 1 and Edison Electric Institute _Statistical Yearbook 1974_, Table 239.

by the Montana Energy Advisory Council (MEAC). It is anticipated that the results will be used for life-cycle costing in design and planning of future state building and heating systems.

A few general comments should be made about the results. The electrical prices forecast below are based on current plans of both public and private utilities with regard to growth of consumption and the addition of generation capacity. In fact, higher energy prices will probably lead to somewhat lower levels of consumption. While the sensitivity of rates to a decrease from projected consumption is investigated, it was beyond the resources of this study to provide a fuller simulation of the supply-demand system. Our results may be interpreted as a supply forecast; that is, we have projected the costs of supplying a given quantity of electricity in 1980, 1985 and 1990. Since electric utilities are publicly regulated, on-average rates will be set at levels that just cover costs.

The task of predicting the future is frought with uncertainty regarding many of the determinants of electrical costs. Some of the major factors are: future fuel prices, generation and transmission costs, future interest rates, the rate of return on capital allowed by the regulatory commissions, and the possibility of delays in planned construction. To minimize error, we have supplemented

our analysis of historical operating data and our review of similar studies by relying on the judgment of a Steering Committee of energy experts assembled by MEAC (Appendix C). The assumptions made for this study are carefully specified in Appendix D.[1]

1.2 Summary of the Results

The findings of this study are that real increases in electric rates in Montana will be on the order of 2% per year.[2]

The specific projection for the Montana Power Company system is summarized in Table A. The base case is the "most probable" projection. The high range is based on an inflation of the base rate by 9.3% in 1980, 11.6% in 1985, and 14.5% in 1990; the low range is based on a deflation of 5.1%, 6.1%, and 8.1% respectively. The rationale for the high and low ranges is discussed in Section 1.3 following.

It should be noted that we use 1973 as our initial year in Table A. The last rate adjustment for the MPCo was in 1972. Average revenue was on the order of 13.5 mls/kwhr in 70-72, but jumped to 15.557 mls/kwhr in 1973 reflecting this

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[1]I would like to acknowledge the assistance of Dave Clark of the University of Montana, who did much of the empirical analysis described herein.

[2]The entire analysis is cast in constant 1975 dollars in order to factor out the effect of inflation in the past, and to avoid the difficult task of predicting it in the future. If, for example, one thinks that inflation will be at the rate of 4%/year, then electric rates faced by consumers in future years will actually be increasing at 6%/year.

TABLE A

PROJECTION OF FUTURE ELECTRICAL RATES FOR THE MONTANA POWER COMPANY SYSTEM, 1973-1990

(Constant 1975 dollars)

	1973	1980	1985	1990	1973-1990
(a) mls/kwhr (1975 $'s)					
high	20.80	26.81	29.74	34.32	
base	20.80	24.53	26.65	29.97	
low	20.80	23.28	25.02	27.54	
(b) % annual growth rates					
high	3.7		2.1	2.9	3.0
base	2.4		1.7	2.4	2.2
low	1.6		1.5	1.9	1.7

new rate allowance.[1] Given that inflation has effected MPCo costs since 1973, but revenues are, of course, largely fixed by law, 1973 is the year when rates most likely cover costs.[2] Given that all our projected future rates are based on the assumption that revenues allowed will just cover costs, 1973 is the logical base of com-

[1]Derived FPC Form 1.

[2]The figure for 1973 is inflated by the consumer price index for electricity. In constant 1975 dollars average revenues for MPCo has declined from 20.79 in 1973 to 16.45 in 1975. If 1975 is used as a base the 1975-80 period shows an increase of 7.5% per year.

parison. Obviously we are abstracting away the problem of regulatory delay, a simplification that is justified in describing long term trends.

The specific projection for BPA rates is an average annual increase of 3.65%.[1] This is based on the announced intention of the BPA to increase rates by 60% in 1979 and 20% in 1981.[2] Both of these increases are deflated by the 5% inflation rate BPA assumes. Beyond 1981, we are assuming a 2% annual increase, based on an analysis by the Oregon Department of Energy[3] and on our results for the MPCo system.

The major cause of rising future real rates are twofold: first, the rising real costs of the factors of production (discussed in detail in Section 3 below); and secondly, a transition from a system dominated by cheap hydro-power to one increasingly reliant on thermal generation.

1.3 Sensitivity Analysis

In addition to a basic projection of rates, this study identifies the effect of changes in certain parameters on electrical prices. The parameters

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[1] See Table 28 below.

[2] Appendix D.

[3] Oregon Department of Energy, Future Energy Options for Oregon, Appendix IV, July 1976.

investigated are listed in Table B. The motivation for the base case level of a variable, and for the likely level of deviation is discussed in detail in Section 3 and the footnotes to Table B.

As an example, the load factor on steam plants is based on the recent historic average of the Corette plant (only 1 1/2 months of operating data on Colstrip #1 is available). The .60 factor investigated is the level used by many other studies (and still exceeds a national average of .54) and the .75 factor is the level MPCo is using in its forecasts. The result here is that at the higher capacity factor, average revenue (following average cost) declined due to the spreading of fixed costs. The .3% change shows that rates are not very sensitive to the parameter.

Variations of only ±3% cover most of the cases, with four notable exceptions. The possibility of an annual 13% real increase in coal costs, 1975-1980, was investigated, based on an MPCo estimate of coal at $10/ton in 1980. This far exceeds most projections, and would result in a 6.5% increase in the base price in 1980.

Another relatively sensitive parameter is the return allowed to common equity. Based on very recent rate orders, it appears that the P.S.C. will allow approximately 11.5%. However, MPCo has historically earned

TABLE B

SENSITIVITY ANALYSIS

Parameter	Parameter Used in Base	Alternative Examined	Average Revenue and Percent Change from Base Case 1980		1985		1990	
Capacity factor on steam plants	.66	.60[1]	24.57	.2%	26.71	.2%	30.20	.2%
		.75[2]	24.47	-.3%	26.56	-.4%	29.87	-.3%
Hydro Conditions (average MW)	404	337[3]	24.70	.7%	26.84	.7%	30.15	.6%
Coal Costs ($/ton 1980)	4.75	8.75[4]	26.15	6.5%	--		--	
Yearly Increase in coal costs	2%	5%[5]	24.79	1.1%	27.40	2.8%	31.36	4.5%
		0%	24.36	-.7%	26.26	-1.5%	29.32	-2.2%
O & M escalation all components	2.5%	5%	25.20	2.7%	28.38	6.5%	32.55	8.6%
		0%	23.88	-2.7%	25.27	-3.8%	27.90	-6.9%
Rate Base		7%[6]	25.36	3.4%	27.55	3.3%	31.05	3.6%
		-7%[6]	23.71	-3.4%	25.76	-3.4%	28.89	-3.6%
Common equity return allowed	11.5%	15.45%	26.37	7.5%	28.58	7.2%	32.23	7.5%
Depreciation rate (% net plant)	.02	.027[7]	24.70	.7%	26.62	.1%	29.59	1.3%
Average Cost of purchases of wholesale power	*	+10%	24.57	.1%	26.71	.2%	30.06	.3%

TABLE B - Continued

Parameter	Parameter Used in Base	Alternative Examined	Average Revenue and Percent Change from Base Case 1980		1985		1990	
Consumption projection	*	price sensitive[8]	27.40	11.7%	31.15	16.9%	38.46	28.3%
Tax rate	.30	.33[9]	25.06	2.2%	27.22	2.1%	30.66	2.3%

*Value varies by year.

[1]Other studies.

[2]MPCo Long Range Plan.

[3]Critical year, MPCo long range plan.

[4]MPCo # of $10/ton, deflated @ 3.4%/year.

[5]5% yearly real increase implies 6.02/ton in 1980.

[6]Approximately twice the average yearly error of the sum of transmission, distribution, A & G plant. Implies simultaneous approximate $40 error on $/kw capacity projection for new generation.

[7]Implies 37-year life on existing plant, rather than 50.

[8]These figures reflect a crude price-sensitivity adjustment. Specifically, a long run weighted elasticity of demand of -1.2 is assumed. One-half of the long run effect is assumed to be seen in consumption in a given year. The implicit price associated with the base case consumption projections is 20.80 mls/kwhr (actual average revenue in 1973).

[9]Approximately, the variation between the 3- and 5-year averages.

15.45%. The effect of the latter on rate of return in 1980 is to increase it from 9.03% to 10.44%. This results in rates 7.5% higher than the base in 1980.

Transmission, distribution and general plant investments are difficult to predict, but account for 60% to 75% of the rate base. Our methodology (see Section 3.3) reproduces historical levels with ± 3.5% accuracy.

The major critical parameter is the sensitivity of projected consumption to price increases. A simulation approach, using an available demand model,[1] is outlined in Appendix G. Unfortunately, good statistical estimates of electrical demand for Montana cover only 39% of the total demand (the residential and commercial sectors). For this reason, we have chosen not to perform the simulation, since it would be partial, at best. As a crude approximation, separate demand equations were fitted to the projected 1980, 1985, and 1990 consumption levels, assuming that these projections are at an implicit constant 1973 price of 20.80 mls/kwhr. Then, based on a long run elasticity of demand of -1.2 (of which one-half of the cumulative effect on quantity demanded was assumed to be seen in any given year) an iterative search was made for equilibrium price. It was found that average

[1]John Duffield and Thomas Power, "Forecasting Coal Development on the Northern Great Plains," a paper presented at the Western Economics Association meeting, San Francisco, California, June 23-27, 1976.

revenue would have to increase by 11.7%, 16.9% and 28.3% in 1980, 1985 and 1990 respectively, in order for an equilibrium to be achieved. At equilibrium revenues allowed just cover costs and the quantity supplied is equal to the quantity demanded. The revenue increases indicated by this approach are probably exaggerated. The 1990 equilibrium, for example, would lower projected electrical consumption from 11.8 billion kilowatt hours to 8.2 billion kilowatt hours or a 30% decline. If this occurred there would probably be adjustments in planned capacity installations which would lower costs. On the other hand, it is possible that consumption adjustments may be even greater than those hypothesized here. To conclude, fuller modeling of the supply-demand simulation should be a high research priority.

The sensitivity analysis summarized in Table B was used to derive the high and low estimates. The approach taken was to sum all positive increases over the base case by year and assume that half of this total increase would occur in the "high" case. The consumption adjustment discussed above and the possibility of the $10 coal increase were excluded from this summation. As an example, if all parameters were changed for 1980 to the extent noted in Table B, 1980 rates would be 18.6% higher. Given that most of the parameters are more or less unrelated (e.g., hydro conditions depend on the weather, common

addition of Colstrip #3, #4, corrected for the MPCo share (.30), the additional revenue requirements may be calculated. Such a calculation is used in lines 11, 12, 13, 14, 15 of Table C (excerpted from Mr. Johnson's testimony). As may be noted, he concluded that the additional revenue requirements between 1974-1981, due only to Colstrip #1, #2, #3, #4 and the Colstrip transmission lines would be 60.8%. Based on his testimony,[1] this figure includes 4% inflation; when the 60.8% is deflated by this rate, a 46.2% real cost increase 1974-1981 is derived. By comparison, taking the actual 1974 average revenue of 17.047 mls/kwhr and inflating to 1975 dollars (19.3014) and comparing to our projected 1981 figure of 24.95,[2] one gets a 29.3% real increase. This suggests that Mr. Johnson would predict an increase in rates between 1974-1981 about 50% greater than our projected increase. However, comparing our 1975 and 1980 figures in real terms,[3] the increase is 49.1%, close to his numbers. This somewhat odd result is due to the fact that in constant dollar terms, actual average revenue for the MPCo declined between 1974 and 1975. Given the great sensitivity of the results to the period selected and to the inflation allowance, we would conclude that the

[1]Op. cit., p. 8151.

[2]Our 1980 @ 1.7% increase.

[3]Average revenue was 16.45 in 1975 and is projected to be 24.53 in 1980.

TABLE C

IMPACT OF COLSTRIP 3 AND 4 ON EXISTING REVENUE REQUIREMENTS OF THE MONTANA POWER COMPANY

	Description	Amount/Ratio	Reference
1.	MPC Investment Units 1 & 2	$135,000,000	MPC, J. Heldt
2.	Carrying Charge Factor	.2463	Westinghouse Report
3.	Revenue Requirements	$ 33,250,000	
4.			
5.	MPC Investment Transmission Line Units 1 & 2	$ 28,000,000	MPC, J. Heldt
6.	Carrying Charge Factor	.16	Westinghouse Report
7.	Revenue Requirements	$ 4,480,000	
8.	Wheeling Revenue	$ 1,000,000	
9.	Net Revenue Requirements	$ 3,480,000	
10.			
11.	Total Investment Units 3 & 4	$669,952,000	MPC, Coldiron Info.
12.	Carrying Charge Factor	.2511	
13.	Total Revenue Requirements	$168,224,947	
14.	MPC Share	.30	
15.	MPC Revenue Requirement	$ 50,467,000	
16.			
17.	Total Investment Units 3 & 4 Transmission line	$202,536,000	MPC Letter, J. W. Ross
18.	Carrying Charge Factor	.1653	
19.	Total Revenue Requirements	$ 33,479,200	
20.	MPC Share	.30	
21.	MPC Revenue Requirements	$ 10,043,000	
22.			
23.	REVENUE REQUIREMENTS SUMMARY		
24.	Units 1 & 2 Plant	$ 33,250,000	Line 3 above
25.	Units 1 & 2 Transmission Line	$ 3,480,000	Line 9 above
26.	Units 3 & 4 Plant	$ 50,467,000	Line 15 above
27.	Units 3 & 4 Transmission Line	$ 10,043,000	Line ~~15~~ 21 above
28.	1974 Revenue Requirements	$ 71,621,000	1974 FPC Form I, p. 414 Col. C., line 37
29.	Total Revenue Requirements	$168,861,000	
30.	Est. 1981 Revenue	$105,000,000	MPC Coldiron Info. and FPC I, p. 414, Col. (f)
31.	Revenue Requirement Deficiency	$ 63,861,000	
32.	Percent increase required	60.8	
33.			
34.	Units 1 & 2 Revenue Requirements	$ 36,~~6~~7 30,000	
35.	Megawatt pro-rate	$ 15,170,075	
36.		$ 21,559,925	
37.	Percentage increase required for Units 1 & 2	20.5	
38.	Units 3 & 4 Revenue Requirements	$ 60,510,000	
39.	Megawatt pro-rate	$ 18,208,244	
40.		$ 42,301,756	
41.	Percentage Increase required for Units 3 & 4	40.3	

results are roughly comparable. However, Mr. Johnson does exclude any allowance for "additional revenue requirement in the period 74-81 arising from existing plant."[1] In addition, the figures he used for estimating capital costs are somewhat lower than current estimates. Substituting current cost estimates would raise his estimate of 46.2% to about a 65% real increase. This seems high based on our analysis.

B. Projections for Other States in the Region

Another basis for comparison of our results are studies recently completed for Oregon by the Oregon Department of Energy[2] and by the Northwest Energy Policy Project (NWEPP)[3] for the states of Idaho, Washington and Oregon. The methodologies used in these studies are essentially similar to that used in the present analysis.[4] They are both "supply" forecasts in their current stages in the sense that no price sensitivity of demand is presumed.

The Oregon study projects annual real price increases for the 1976-1986 period for private utilities of 3.18% and annual increases for public utilities of 2.37%. These results are in the range we have projected.

The transition of the Oregon system is rougly comparable to our own: current dominance of cheap hydropower

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[1]Op. cit., p. 8124.

[2]Xerox source attached.

[3]Xerox source attached.

[4]Discussed more fully in Section 2.

(96.6% in 1974) declining rapidly in the future to 51.7% in 1990. For the MPCo system similar shares are 78.6% in 1975 and 32.4% in 1990.

The results of the NWEPP report are preliminary and not for quotation; however they project a real price increase for the three northwestern states for 1974-2000 very close to our 1973-1990 figure.

One would expect the rate projections of other states to vary somewhat due to current and future public/private and hydro/steam shares of net generation. However, given the interconnection of the regional system (discussed more fully in Section 3.5 below), one would also expect roughly similar results. (Especially given that 50% of Colstrip #1, and #2 and 30% of #3 and #4 is being purchased by West Coast utilities.) We would conclude that the results of similar studies for other states in the region <u>are</u> similar to our projections. It should be noted again, however, that these studies are limited to an analysis of supply conditions at this stage. When the Oregon and NWEPP studies include the demand side in their simulations, one would expect their results to change--possibly substantially.

2. METHODOLOGY

This section describes the methodology used in this study in very general and basic terms. A more specific and complex discussion is deferred to part 3 and the appendices. We will begin by noting that the future price of electricity will depend on both supply and demand factors.

On the supply side, given the production function and the prices of inputs, costs are completely determined. The production function is the physical relationship between inputs and outputs, e.g., given a certain physical plant and a certain amount of coal, it is possible to produce a given amount of electricity. If one knows the cost of the coal and the cost of the physical plant, the cost of generating the given amount of electricity is also derived. Existing studies of the costs of producing electricity vary mainly with regard to the extent of disaggregation of the various cost elements.

In this study, costs are in two major components--fixed costs associated with investment in plant and equipment and variable costs associated with variable inputs such as fuel. Fixed costs are estimated separately for generation, transmission, distribution and general plant (see 3.1, and 3.3 below). Variable costs are primarily operation and maintenance expenses

for each of the fixed-cost categories plus fuel expenses (see 3.4, and 3.2 below). Variable costs are a function of the amount of electricity produced.

By contrast with the level of disaggregation taken in this study, a recent analysis by the Oregon Department of Energy[1] identifies the components of generation costs, but projects transmission, distribution, general plant, tax, and depreciation on non-generating plant as a lump-sum "non-power" cost. However, the level of disaggregation taken here is similar to that in a recent study for the Northwest Energy Policy Project (NEWPP)[2] and a simulation model developed at MIT.[3] Another major difference between these studies is the extent to which interrelationships between various fuels are specified; in this regard the MIT study is much more sophisticated.

On the demand side, consumption of electricity depends on the price of electricity, the price of major substitutes such as natural gas; it also depends on income and population.

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[1]Oregon Department of Energy, Future Energy Options for Oregon, Appendix IV, Future Electrical Prices in Oregon (July 1, 1976).

[2]Northwest Energy Policy Project, Conventional Energy Resources (preliminary, August 1976).

[3]Paul L. Joskow and George Royanski, "The Effects of a Nuclear Moratorium on Regional Electricity Prices and Fuel Consumption by the Electric Utility Industry," mimeo, September 1976.

In attempting to forecast the equilibrium price of electricity, one approach is to assume that future consumption is independent of price. For example, one might assume that the consumption of electricity will continue to grow at historical rates. Price is then determined by using the supply analysis to determine how much it will cost to produce an amount of electricity equal to projected consumption in some future year. Given the total cost of producing the electricity, and given that electric utilities are regulated monopolies, the public service commissions will allow prices such that revenue just cover costs. Prices are thereby determined. The aforementioned Oregon Department of Energy and NWEPP studies are currently of this type. This approach is also taken in this study (see Appendix H) using the consumption forecast developed by the Montana Power Company.

Another approach is to assume that, other things constant, the quantity demanded of electricity depends on the price. This suggests that if one follows the previously described approach, and finds, for example, that in 1980 5 billion kwhrs of electricity can be produced at 16 mls/kwhr, this may not, in fact, be the "equilibrium price." Possibly at 16 mls/kwhr only 4.6 billion kwhrs of electricity will be consumed. The problem is then one of identifying a price at which the

quantity supplied and the quantity demanded are equal. Given equations specifying supply and demand, equilibrium can be identified either through simultaneous solution or by substituting different values of price until a solution is reached. This study will not use this approach to the problem, although an appropriate methodology is outlined in Appendix G, based on a recent study.[4]

In addition to the price projection studies referred to above, this analysis has relied on a number of other studies concerned with specific components of electrical costs. These are referred to as appropriate in the following section.

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[4]Duffield and Power, op. cit.

3. SIMULATION MODEL OF THE MONTANA POWER COMPANY

3.1 Generating Capacity

A critical determinant of future electrical prices is the fixed costs associated with generating capacity. As an initial step in determining those fixed costs, it is necessary to project future generating capacity. The approach in this study is to use the capacity additions now being planned by the Montana Power Company (Table 1 from the Montana Power Company Long Range Plan summarizes this information in terms of "average energy" available.) The major additions to existing capacity (broken out more fully in Table 2 from MEAC's Montana Historical Energy Statistics) are Colstrip #2 (330 MW of which the MPCo share is 50%), Colstrip #3 and #4 (twin 700 MW units of which the MPCo share is 30%), and a 350 MW steam unit in 1989-90. The latter is only one of several possibilities in the far future, but is included in the projection based on the Steering Committee assumptions (Appendix D).

Once future capacity is known, assumptions can be made concerning the percentage of the time that a given plant will actually be in operation (the plant or load factor) to derive future generation. We have calculated the recent 10-year average hydro-electric generation at 3,539,867 kwhrs/year, and will use this for the projection. This corresponds to a .8579 load factor as

TABLE 1

THE MONTANA POWER COMPANY
LOADS AND RESOURCES
(Including Units #3 & #4)
AVERAGE ENERGY (MW)

Operating Year (July-June)	1975-76	1976-77	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86
Mean Energy Load	628	655	694	745	800	846	887	932	979	1028	1080
Resources											
Hydro-Critical	337	337	337	337	337	337	337	337	337	337	337
Bird											
Corette	157	157	157	157	157	157	157	157	157	157	157
Colstrip No. 1	103	165	165	165	165	165	165	165	165	165	165
Colstrip No. 2	--	151	165	165	165	165	165	165	165	165	165
Colstrip No. 3	--	--	--	--	--	193	210	210	210	210	210
Colstrip No. 4	--	--	--	--	--	--	193	210	210	210	210
BPA	40	40	35	30	20	10	5	--	--	--	--
BPA (Wheeling)	10	10	11	11	12	12	13	13	14	14	15
BPA (Offsets)	11	--	--	--	--	--	--	--	--	--	--
BPA (Energy for Peak Trade)	--	--	--	(14)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
Hanford (Debt Service)	19	19	20	20	20	--	--	--	--	--	--
Hanford (Extension)	49	49	16	--	--	--	--	--	--	--	--
Hanford (5 mill)	5	--	--	--	--	--	--	--	--	--	--
WWP (Hanf. Trade)	(18)	(19)	(20)	(20)	(20)	--	--	--	--	--	--
WPPSS #1	--	--	--	--	--	68	68	68	68	68	68
Puget	4	(5)	--	--	--	--	--	--	--	--	--
Utah	(30)	(60)	(10)	--	--	--	--	--	--	--	--
Total Resources	687	844	876	851	838	1089	1295	1307	1308	1308	1309
Surplus over Firm Load with Critical Water	59	189	182	106	38	243	408	375	329	280	229
Less Maint. & Avail. Adj.	47	84	76	76	76	153	208	184	181	181	181
Interruptible included in Adj.	13	14	15	16	17	18	19	21	22	24	25
NET SURPLUS	12	105	106	30	(38)	90	200	191	148	99	48
Median Water Adder	48	50	51	51	51	51	51	51	51	51	51
Bird (Maint. & Avail. deducted) (only if oil is available)	60	60	60	60	60	60	60	60	60	60	60

Scheduled dates of operation
Colstrip No. 1 - Nov. 14, 1975
Colstrip No. 2 - Aug. 1, 1976
Colstrip No. 3 - Aug. 1, 1980
Colstrip No. 4 - Aug. 1, 1981

Source: Montana Power Company Long Range Plan, Exhibit "G", p. 1.

Table 2
Electric Generating Capacity in Montana

	Existing Power Plants	Type	Owner	Year Of Completion	Name Plate Capacity (MW)	Location
1.	Madison	H	MPC	1912	9.0	Madison River
2.	Hauser	H	MPC	1912	17.0	Missouri River
3.	Holter	H	MPC	1918	38.4	Missouri River
4.	Black Eagle	H	MPC	1929	16.8	Missouri River
5.	Rainbow	H	MPC	1929	35.6	Missouri River
6.	Ryan	H	MPC	1929	48.0	Missouri River
7.	Morony	H	MPC	1930	45.0	Missouri River
8.	Cochrane	H	MPC	1957	48.0	Missouri River
9.	Mystic Lake	H	MPC	1927	10.0	West Rosebud Creek
10.	Flint Creek	H	MPC	1935	1.0	Flint Creek
11.	Milltown	H	MPC	1929	3.0	Clark Fork River
12.	Thompson Falls	H	MPC	1929	30.0	Clark Fork River
13.	Kerr	H	MPC	1938	168.0	Flathead River
14.	Noxon	H	WWP	1960	230.0	Clark Fork River
15.	Big Fork	H	PPL	1930	4.26	Swan Lake
16.	Fort Peck	H	CE	1940	165.0	Missouri River
17.	Canyon Ferry	H	BR	1954	50.0	Missouri River
18.	Hungry Horse	H	BR	1953	285.0	S. Fork Flathead River
19.	Yellowtail	H	BR	1966	250.0	Bighorn River
20.	Big Creek	H	FIP		0.36	Big Creek
21.	Troy	H	MLP	1916	4.5	Lake Creek
22.	Libby #1	H	CE	1975	105.0	Kootenai River
23.	Libby #2	H	CE	1976	105.0	Kootenai River
24.	Libby #3	H	CE	1976	105.0	Kootenai River
25.	Libby #4	H	CE	1976	105.0	Kootenai River
	Total Hydropower				1,878.92	
26.	Baker	IC	MDU		1.0	Baker
27.	Glendive	S	MDU		7.0	Glendive
28.	Lewis and Clark	S	MDU		50.0	Sidney
29.	Miles City	GT	MDU		30.1	Miles City
30.	Libby	S	MLP	1927	13.3	Libby
31.	Libby	GT	PPL	1972	26.6	Libby
32.	Frank Bird	S	MPC	1951	69.0	Billings
33.	J. E. Corette	S	MPC	1968	172.8	Billings
34.	Colstrip I	S	MPC	1975	330.0	Colstrip
35.	Colstrip II	S	MPC	1976	330.0	Colstrip
	Total Fuels				1,029.8	
	Total Fuels and Hydropower				2,908.72	

H = Hydro, S = Steam, IC = Internal Combustion, GT = Gas Turbine

Source: Bonneville Power Administration, as reported in Terry Wheeling, Montana Historical Energy Statistics, September 1976, p. 94.

noted in Table 3. During this period hydro fluctuated from a low of 3.16 million kwhrs in 1973 to a high of 3.76 in 1971--a 19% variation. Obviously using <u>average</u> hydro introduces a random error into the analysis; also, obviously, it is hard to avoid the error short of accurately forecasting the weather. Our forecast corresponds to "average energy" of 404 MW, close to the MPCo projection (Table 1) of 337 MW "hydro-critical" plus the "median water adder" of 48 MW or a total of 385 MW.

Turning to the steam forecast, the Frank Bird plant is used only sparingly (at 6.12% of capacity for the most recent period) due to high variable costs. We will assume that it will not be used in the forecast period; the Bird plant accounted for only .7% of generation in the recent past, and its use is subject to the availability of oil.

The Corette plant is assumed to operate at its most recent three-year average load factor of .662 (Table 3). The five-year average is substantially lower (.585) and closer to the national average for steam plants (including oil-fired) of .52.[1] A recent study by the Oregon Department of Energy[2] uses a .60 plant factor; however

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[1] FPC <u>Steam-Electric Plant Construction Costs and Annual Production Expenses--1977</u>. The 1972 figure was .54; this includes all fossil-fuel fired plants.

[2] <u>Op. cit.</u>

TABLE 3

MPCo GENERATION CAPACITY, 1976-1990

Date	Generation	MKWH Net Generation	Load Factor	Average MW	Capacity (MW)
	Hydro @ 10 year	3,539,867	.8579	404	471.03
	Bird	0			69.0
	Corette	1,002,497	@ .662	114.4	172.8
15 Nov 75	Colstrip #1	956,592	"	109.2	165
1 Aug 76	Colstrip #2	956,592	"	109.2	165
Oct 80	Colstrip #3	1,217,640	"	139.0	210
Aug 81	Colstrip #4	1,217,640	"	139.0	210
Jan 90	350 MW Steam	2,029,692	"	231.7	350

Source: Derived FPC Form 1 and MPCo Long Range Plan.

the MPCo is using a .75 factor in its forecasts. We have chosen to use the .662 as a median figure between the .60 and .75 extremes to project all MPCo steam. (This is a parameter where sensitivity analysis was performed.) Table 3 summarizes future maximum net generation from all sources. (This excludes, of course, the possibility of purchase and resale as evident in Table 1; this will be discussed in Section 3.5 below.)

Once future capacity is estimated, a dollar value must be placed on the value of the capital investment for its inclusion in the rate base. Table 4 summarizes

TABLE 4

ACTUAL AND PROJECTED CAPITAL COSTS FOR COAL-FIRED GENERATION PLANTS (000 1975 dollars)

Capacity	MPCo Share Capacity	Capacity	AFUDC[1]	Gross valuation	$/KW	(incl. AFUDC) $/KW
Colstrip #1 330	165	79,900.7[2]	12,978.0	92,878.7	484.2	562.9
Colstrip #2 700	assumed to be the same					
Colstrip #3	210	108,227.5	17,576.1	125,803.6[3]	515.4	599.1
Colstrip #4	assumed to be the same					
Jim Bridger 500	0				425.0[4]	
Oregon estimate 1980					537.0[4]	
Oregon estimate 1990					857.0[4]	
350 MW MPCo Unit for 89-90	350	299,950.0	48,711.9	348,661.9	857.0	996.2[5]

[1]Allowance for funds used during construction at the 16.24% estimated for Colstrip #3, #4 by MPCo (Dick Davenport).

[2]FPC Form 1.

[3]15% (MPCo share for #3) of the $1,008,000,000 MPCo estimate for #3 and #4 total, less 140,794,000 inflation, and including 140,857,000 AFUDC, in 1976 dollars deflated by the wholesale price index increase for Oct 75 to Oct 76 of 3.4% to get in 1975 dollars.

[4]Oregon Department of Energy, Appendix IV to Future Energy Options for Oregon, p. 31, Table 32. Includes estimated addition SO_2 removal equipment.

[5]Based on Oregon estimate for 1990 plus 16.24% for AFUDC.

the actual and projected costs of MPCo's planned capacity additions. Based on the cost reported in FPC Form 1, Colstrip #1 cost $79,900,700 in 1975 dollars. An allowance for funds used during construction (AFUDC) is also included in the rate base by the Montana PSC (Appendix A). Based on the AFUDC anticipated for Colstrip #3 and #4[2] of 16.24% of total costs, an AFUDC for Colstrip #1 of 12,978,000 is included in gross valuation (Table 4). It is assumed that Colstrip #2 will face identical costs in 1975 dollars.

Colstrip #3 and #4 are currently estimated to cost $1,008,000,000, of which 140,794,000 is inflation or $867,206,000 in 1976 dollars.[2] Deflating this to 1975 dollars by the most recent wholesale price index increase of 3.4% gives a total cost in 1975 dollars of 838,690,000. Montana Power's share of these plants is 30%, resulting in a gross valuation of $125,803,600 for each. These estimates, on a $/Kw basis, are compared with the Oregon Studies projection (using the Jim Bridger Plant) in Table 4. They estimate $537/Kw in 1980, including pollution control costs. This is close to the Colstrip #3 and #4 estimate of 515.37 $/Kw (excluding AFUDC). We have therefore used the Oregon estimate of 857.00 $/Kw in 1990 to project capital costs on the proposed 350 MW unit (Table 4).

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[1]Communication with Dick Davenport of MPCo.

[2]Ibid.

It should be noted at this point that the range of \$/Kw costs projected by MPCo was not accepted uncritically. Table 5 is reproduced from the Rand Corporation's recent summary of the literature on capital costs for new generation.[1] These studies are mostly from the early '70s, and project numbers that now seem low--on the order of \$200 to \$400/Kw. However, the AFUDC allowances of 19% to 20% are close to MPCo's 16%. For further comparison, the Northwest Energy Policy Project used \$480/Kw for all new plants with a real cost escalation rate of 2% or \$504 in 1980.[2] Impacts of Alternative Electricity Supply Systems for California used a \$425/Kw figure.[3]

A final source was a recent paper written at MIT,[4] which projects capital costs for coal-fired plants at 429.38 in 1980 and 801.45 in 1990 (Table 6). The former figure seems low and the latter is in the range used for the 350 MW plant.

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[1] The Long Run Marginal Costs of Energy, Rand Corporation, February 1975.

[2] Op. cit., p. 124.

[3] Op. cit., p. 27.

[4] Joskow and Royanski, op. cit.

TABLE 5

ALTERNATIVE ESTIMATES OF CAPITAL COSTS FOR NEW GENERATING CAPACITY

(For plants of roughly 1000 MW size)

Source of Estimate	Date of Publication	Type of Capacity	Date of Construction[a]	Type of $	Cost, $/kW	Current Cost,[b] $/kW	Includes Initial Fuel Inventory?	Includes Interest during Construction?
AEC, WASH-1184 (Ref. 3)	1972	LWR	1970	1970	252	302	Yes(?)	?
		Coal			205	246	N.A.[c]	
		LWR[d]	2000		180-185	216-222	Yes(?)	
		Coal			165-175	198-210	N.A.	
McTague et al., *Nuclear News* (Ref. 4)	February 1972	LWR	1979 completion	1971	300	339	Yes(?)	7½% per annum during 7-year project period (totals approximately 20% of base plant cost)
		Coal			260	294	N.A.	
		LWR	1989 completion		340	384	Yes(?)	
		Coal			280	316	N.A.	
AEC, WASH-1230, Vols. 1-IV (Refs. 5-8)	June 1972	PWR[e]	Completion in early 1970s	1971	211	238	No	No
		BWR[f]			213	241	No	
		Coal			174	197	N.A.	
		Oil			158	179	N.A.	
Roe and Young, *Power Engineering* (Ref. 9)	June 1972	LWR	1971 start	Current	250-300	287-344	Yes(?)	Yes(?)
		Fossil			180-240	206-275	N.A.	
		LWR	1975 start		300-400	300-400[g]	Yes(?)	
		Fossil			220-300	220-300[g]	N.A.	
		LWR	1980 start		400-500	300-400[h]	Yes(?)	
		Fossil			325-400	220-300[h]	N.A.	
Baron, *Pub. Util. Fortnightly* (Ref. 10)	July 1972	LWR	Early 1970s	1970	280	356	Yes(?)	Yes
		Oil			180	216	N.A.	
NPC, *U.S. Energy Outlook* (Ref. 11)	December 1972	LWR	Pre-1972 start	1970	300	360	Yes(?)	Yes
			Post-1970 start		400	480	Yes(?)	
		Coal	Pre-1972 start		220	264	N.A.	
			Post-1972 start		300	360	N.A.	
		Oil	1970s		200	240	N.A.	
		Other[i]	1970s		200	240	N.A.	
Nuclear News Buyer's Guide (Ref. 12)	February 1973	LWR	1980 completion	Current	520	337[j]	?	Yes (approximately 19% of base plant cost, including escalation)
FPC, Technical Advisory Committee[k] (Ref. 13)	August 1973	LWR	1973 start	Current(?)	275	275	Yes	Yes(?)
		Fossil			162	162	N.A.	
		LWR	1975 start		356	317	Yes	
		Fossil			199	177	N.A.	
Olmsted, *Electrical World* (Ref. 1)[m]	September 1973	LWR	Late 1970s completion	1973[ℓ]	325	325	Yes(?)	Yes(?)
		Coal			250	250	N.A.	
		LWR	Late 1980s completion		340	340	Yes(?)	
		Coal			260	260	N.A.	

[a] Dates of completion or start are reported if given.

[b] 1973 dollars.

[c] N.A. = not applicable.

[d] Plant size of 2500-3000 MW assumed.

[e] PWR = pressurized water type of LWR.

[f] BWR = boiling water type of LWR.

[g] Current values used, since deflating at inflation values of 4 to 6 percent results in lower figures than for the 1971 case.

[h] Figures for a 1975 start are used, since real costs are nearly constant between 1975 and 1980 if a 5 percent annual rate of inflation is assumed.

[i] Conventional hydroelectric, pumped storage, diesel, and gas turbine units (average for all such types).

[j] Total, ex-escalation of $402/kW taken as 1976 dollars deflated at 6 percent per annum to 1973.

[k] Private communication.

[ℓ] Deflated at 6 percent per annum.

[m] Figures reported are estimated by the author on the basis of the data given in the forecast; they are only approximate and may differ from the assumptions actually used in the forecast.

Source: The Long Run Marginal Costs of Energy, Rand Corporation, February 1975.

TABLE 6

UNIT CAPITAL COSTS ($/KW) FOR COAL-FIRED GENERATION CAPACITY

(1975 dollars)

Year		regional multipliers	Mountain Region
1975	338	.9097	307.48
1980	472	.9097	429.38
1985	643	.9097	584.94
1990	881	.9097	801.45
1995	1144	.9097	1040.70

Source: Paul J. Joskow and George Rozanski, "The Effects of a Nuclear Moratorium on Regional Electricity Prices and Fuel Consumption by the Electric Utility Industry," mimeo, Department of Economics, Massachusetts Institute of Technology, September 1976, derived Tables A-7, A-8.

3.2 Operation and Maintenance Expenses: Generation

The historical variable costs of generation for the MPCo hydro system and for specific steam plants is reported in Table 7. The most recent hydro O & M expense is 1.1414 mls/kwhr, with an increase in real cost (based on historic values inflated to 1975 dollars by the wholesale price index) of 6.38% per year for the recent 10-year period. For the study, we will use the 1975 value and inflate it by the 2.5% rate used by the Oregon study.[1] Their rationale is that 2.5% is the likely real increase in labor costs (the main determinant of O & M). Their labor increase is based on a deflated Handy-Whitman index for Pacific Coast construction labor 1965-1975. Another projection is by the NWEPP at -.55%/year (for average <u>total</u> cost). The estimates to be used for this study are summarized in Table 8.

The Frank Bird plant parameters are at their historic values in Tables 7 and 8.

The Corette plant shows a 1975 O & M of .6116 mls/kwhr and a real cost decline of -5.8%/year. The 1975 value will be used in the projection, but at a real cost increase of 2.5%. The Oregon study used +5% 1976-86 and 2.5% thereafter. The NWEPP used a 1% rate (including fuel). The Rand study assumes a 2.7% increase. The

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[1]Oregon Energy Department, <u>op. cit.</u>

TABLE 7

SUMMARY OF OPERATING EXPENSE PARAMETERS (CONSTANT 1975 DOLLARS)

	1975	Average 3 year	Average 5 year	Average 10 year	OLS trend
A. Generation					
Hydroelectric					
O & M (mls/kwhr)	1.1414	1.2655	1.1817	.99714	.06383
generation (kwhrs)	3,633,814,000	3,485,063,000	3,582,681,000	3,539,867,000	
capacity (MW)	469.940	469.940	469.940	469.940	
Load factor	.8827	.8466	.8703	.8599	
Frank Bird					
O & M (mls/kwhr)	32.59	14.7107	11.1134		.5545
Fuel cost (mls/kwhr)	12.49	12.1793	10.2698		.1584
Generation (kwhrs)	2,599,000	37,000,000	32,433,000		
Capacity	69 MKWH				
Load factor	.004	.0612	.0536		
Corette					
O & M(mls/kwhr)	.6116	.66873	.71898		-.05798
Fuel Cost (mls/kwhr)	2.751	2.7392	2.8264		-.02466
Generation (kwhrs)	1,046,132,000	1,002,491,000	885,815,000		
Capacity	172.8 MKWH				
Load factor	.69	.662	.585		
Colstrip #1					
O & M	1.44				
Fuel Cost	3.68				
Generation	844,320				
Capacity	179,186				
Load factor	.5378				

TABLE 7 - Continued

	1975	Average 3 year	5 year	10 year	OLS trend
B. Transmission, Distribution, A & G					
Transmission O & M (mls/kwhr)	.384	.4284	.4577	.42669	.0155
Distrubution O & M (mls/kwhr)	.969	1.01586	1.01716	1.00641	.0024
A & G (mls/kwhr)	1.4921	1.4637	1.37736	1.31816	.01464

Source: Derived FPC Form 1

TABLE 8

INPUTS FOR SOLUTION ALGORITHM: GENERATING PARAMETERS

(CONSTANT 1975 $)

	All Hydro	Frank Bird	Corette	Colstrip #1	Colstrip #2	Colstrip #3	Colstrip #4	350 MW
O & M (Operation and maintenance) current or date of operation (mls/kwhr)	1.1414	32.59	.6116	1.44	1.44	1.42	1.42	1.82
O&M escalation per year	.0200	.5545	.0250	.0250	.0250	.0250	.0250	.0250
FC (Fuel costs) current or date of operation (mls/kwhr)	--	12.49	2.751	3.68	3.68	3.00	3.00	3.66
FC escalation per year	--	.1584	.020	.020	.020	.020	.020	.020
Q_{Gi} (Generation) (000 kwhrs)	3,539,867	0	1,002,497	956,592	956,592	1,217,640	1,217,640	2,029,692

Source: Derived FPC Form 1 and Tables 1-7.

fuel costs for Corette are 2.751 mls in 1975, and show a 2.5% decline historically. In the face of rising energy prices, some increasing rate seems likely. The MPCo has suggested coal at $10/ton in 1980; however, since the Corette plant bought coal at $4.30 in 1975, this is a 16.84% annual increase. We will use instead the 2% fuel escalation used by the Oregon study. Joskow, in the MIT study, used a 1.2% real increase and the NWEPP used 1.0% (including other O & M components). This, of course, assumes that there is no change in the heat rate, so that all increases in per unit fuel cost ($/ton) show up in the mls/kwhr cost of fuel. The $10/ton figure suggested by MPCo was accepted by the Steering Committee at the December 6 meeting--perhaps in lieu of better information. Given that assumption, sensitivity analysis was performed on this parameter.

Colstrip #1, operating for only 1 1/2 months but at an annualized load factor of .54, had O & M of 1.44 and fuel costs of 3.68. The latter figure included some propane but is still somewhat less than the comparable figure for the Jim Bridger plant of 3.83. Similarly, the 1.44 figure for O & M is slightly less than the 1.84 O & M figure reported in the Oregon study for the Jim Bridger plant. Therefore, the recent O & M costs will be used. They will be escalated at the same rates as the Corette plants (Table 8). It will be assumed that

Colstrip #2 will face the same costs.

For Colstrip #3 and #4, MPCo is estimating 1.42 mls/kwhr for O & M (Appendix B). This estimate will be used with the .0250 escalation as for the other plants. The heat rate on #3 and #4 is estimated to be 10,819 BTU/kwhr.[1] Coal at 4.31/ton (the Colstrip #1 price) in 1975 inflated at 2%/year to 4.75 in 1980. Given the heat rate, and an assumption of 8454 BTU/lb. of coal (as for Colstrip #1 in 1975), a 3.004 mls/kwhr figure for fuel is derived for #3 and #4.

The Colstrip parameters are inflated for the 350 MW unit planned for 1990.

3.3 Transmission and Distribution Capacity

Generating capacity planned and associated costs faced by any given utility can be fairly easily derived, as discussed in 3.1 above. However, transmission, distribution and general plant investments (69% of net plant in 1976) are the sum of many different capital goods ranging from substations to meters to desks. Our approach here has been to examine the historical relationship between aggregate investment in each of these categories and specific aggregate variables. Tables 9, 10, 11 and 12 summarize our statistical analysis.

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[1]Communication with the MPCo.

TABLE 9

REGRESSION ANALYSIS: TRANSMISSION PLANT REGRESSED ON NET GENERATION AND TOTAL ENERGY

Y Transmission* Plant	X_1 Net Generation	X_2 Total Energy	
$134,814,835	4,901,900 MKWH	6,091,838 MKWH	1975
132,106,021	4,596,576	5,760,342	1974
122,544,152	4,294,689	5,241,618	1973
119,697,641	4,512,585	5,416,645	1972
113,845,062	4,418,435	5,057,009	1971
108,578,646	4,403,893	5,208,003	1970
105,737,944	4,111,611	5,019,105	1969
83,019,164	3,854,062	4,686,980	1968
72,199,038	3,507,227	4,585,108	1967
70,874,335	3,675,740	4,546,927	1966

r = .95807	r = .93162
b = 51.3599	b = 43.5364
a = -110,797,000	a = -118,371,150
t = 9.4566	t = 7.2509

Source: Derived FPC Form 1.

*The general form of the equation is: $Y = a + b\,x_n$. Since Y is a capital stock of different year vintages, Y in any given year is the previous year value (in 1975 dollars) plus the nominal change over the previous year plus 2% to include depreciation allowance inflated to 1975 dollars.

TABLE 10

REGRESSION ANALYSIS: DISTRIBUTION PLANT REGRESSED ON SALES TO ULTIMATE CUSTOMERS AND NUMBER OF CUSTOMERS

Y Distribution* Plant	X_1 Sales to Ultimate Cust.	X_2 Number of Customers	Time
$181,453,644	4,319,463	197,721	1975
171,975,980	4,313,797	193,259	1974
166,488,684	4,248,350	187,559	1973
157,034,587	4,319,887	182,314	1972
147,999,549	4,109,606	176,908	1971
140,088,035	4,116,236	172,352	1970
133,738,764	3,985,358	169,606	1969
126,621,777	3,501,944	167,888	1968
120,445,205	3,258,892	165,995	1967
114,649,020	3,646,627	164,523	1966

r = .86269	r = .98719
b = 51.5462	b = 1899.12
a = -59,208,545	a = -191,637,843
t = 4.82496	t = 17.5014

Source: Derived FPC Form 1.

*General form of the equation is: $Y = a + b\, x_n$. Distribution plant is in adjusted 1975 dollars.

TABLE 11

REGRESSION ANALYSIS: GENERAL PLANT REGRESSED ON SALES TO ULTIMATE CUSTOMERS AND NUMBER OF CUSTOMERS

Y General* Plant 1975 Adj. $	X_1 Sales to Ultimate Customer MKWH	X_2 Number of Customers	Time
20,257,286	4,319,463	197,721	1975
19,531,571	4,313,797	193,259	1974
19,017,933	4,248,350	187,559	1973
17,455,558	4,319,887	182,314	1972
16,309,694	4,109,606	176,908	1971
15,184,465	4,116,236	172,352	1970
13,998,603	3,985,358	169,606	1969
13,552,312	3,501,944	167,888	1968
12,939,538	3,258,892	165,995	1967

r = .8376	r = .98889
b = 5.9593	b = 234.42089
a = -7,480,212	a = -25,557,229
t = 4.05682	t = 17.603

Source: Derived FPC Form 1.

*The general form of the equation is: $Y = a + b\,x_n$. General plant is in adjusted 1975 dollars.

TABLE 12

REGRESSION ANALYSIS: NUMBER OF CUSTOMERS REGRESSED ON MPCo SERVICE AREA POPULATION, MONTANA POPULATION AND TIME

Y Number Customers	X_1 Time	X_2 MPC Population	X_3 Montana Population	Year
197,721	10	543,400	747,500	1975
193,259	9	535,200	737,000	1974
187,559	8	532,500	729,800	1973
182,314	7	522,500	716,100	1972
176,908	6	516,300	709,400	1971
172,352	5	504,400	694,400	1970
169,606	4	508,700	693,800	1969
167,888	3	505,300	693,200	1968
165,995	2	505,000	701,100	1967
164,523	1	505,200	702,100	1966

r = .97689	r = .98083	r = .95045
b = 3822.212	b = .7926	b = .57631
a = 156,790	a = -232,634	a = -232,776
t = 12.9298	t = 14.24	t = 8.6475
# cust. on time	# cust. on MPC pop.	# cust. on Mont. pop.

Source: Derived FPC Form 1.

*The general form of the equation is: $Y = a + b\ x\ n$.

Our findings are that there are significant and fairly stable relationships between transmission plant and net generation; between distribution plant and number of customers and between general plant and number of customers. Net generation is an exogenous variable in our model (as discussed further in 3.5 below), given generation capacity and given load factors (Table 14). Therefore, transmission plant can be predicted for any given year, based on our net generation forecast. The equation used is listed in Table 13.

Besides the above relationship, we found (Table 12) that the number of customers using the MPCo system is a stable and statistically significant function of Montana population. We have taken Montana population based on a Montana Department of Community Affairs projection (Table 14), derived number of customers, and used number of customers to derive distribution and general plant. The specific relationships are given in Table 13, parts 2 and 3.

As a test of the model's accuracy, it was used to reproduce the 1966-1975 period. The estimate of transmission plant varied from the actual by an average of 5.3%/year; distribution was off by 5.7%/year and general plant by 4.5%. The total for non-generating capacity varied from actual by an average of only 3.2%, and no year was off by more than 6%. In the sensitivity

TABLE 13

SOLUTION FOR NON-GENERATING ADDITIONS TO GROSS PLANT

1. <u>Transmission plant</u> in year t = TS_t

    net generation in year t = Q_{Gt} <u>as projected</u>

  then

    $$TS_t = -110{,}797{,}000 + 51.3598\ (Q_{Gt})$$

2. <u>Distribution plant</u> in year t = DS_t

    number of customers in year t = NC_t

    Montana population in year t = MP_t

    (a) $NC_t = -232{,}776 + .57631\ (MP_t)$

    (b) $DS_t = -191{,}637{,}843 + 1899.12\ (NC_t)$

3. General plant addition year t = PS_t

    $$PS_t = -25{,}557{,}229 + 234.421\ (NC_t)$$

Source: Regression Analysis as described in Tables 9, 10, 11, 12.

TABLE 14

INPUT SERIES FOR PROJECTING GROSS PLANT ADDITIONS BY YEAR

Year	Net Generation (QGt) MKWH	Montana Population[1] MP_t[1]
1975	4,901,900[2]	747,400
1976	5,977,252[3]	754,540
1977	6,455,548[4]	761,680
1978	6,455,548	768,820
1979	6,455,548	775,960
1980	6,861,022[5]	783,100
1981	8,180,538[6]	795,600
1982	8,890,828[7]	808,100
1983	8,890,828	820,600
1984	8,890,828	833,100
1985	8,890,828	845,600
1986	8,890,828	857,680
1987	8,890,828	869,760
1988	8,890,828	881,840
1989	8,890,828	893,920
1990	10,920,520	906,000

[1]Source: Energy Consumption in Montana: Projections to 1990, MEAC and Mountain West Research, Inc., August 1976, p. 13. (Original source is the Montana Department of Community Affairs. Values between 1975, 1980, 1985 and 1990 were interpolated.)

[2]Actual.

[3]10-year average hydro, plus 3-year average Corette, plus zero Bird, plus Colstrip #1 @ .662 and 1/2 Colstrip #2 @ .662 plant factor.

[4]Includes #2 at .662.

[5]Colstrip #3 at 1/3 year at .662.

[6]Includes Colstrip #4 at 5/12 of a year and Colstrip #3 for the year.

[7]Includes Colstrip #4.

[8]Includes 350 MW @ .662 factor.

analysis described in section 1.3 above, the effect of a 7% change in the rate base was examined; this is approximately double the actual error on the projected totals.

Our projections are summarized in Table 15. This table also summarizes gross valuation including the generating plant additions discussed in 3.1 above.

A more sophisticated, region-specific analysis, which disaggregated transmission and distribution equipment by line transformers, substations, meters, etc. has been completed.[1] However, any additional reliability due to disaggregation along equipment lines is undoubtedly outweighed by the fact that regional averages are used rather than parameters specific to the MPCo. An even more complex methodology, which takes account of the shape of the load curves (extent and timing of peaks), is found in a recent study by Cicchetti et al.[2] The methodology would be appropriate, however it is beyond the resources of this study.

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[1]Martin L. Baughman, et al., "Electric Power Transmission and Distribution Systems: Costs and their Allocation," National Technical Information Service, July 1975.

[2]Charles J. Cicchetti, et al., The Marginal Cost and Pricing of Electricity, Planning and Conservation Foundation. Sacramento, California, June 1976.

TABLE 15

ADDITIONS TO GROSS PLANT

(constant 1975 dollars)

Year						
1975	134,814,000	181,454,000	19,618,000	335,886,000	86,400,000	422,286,000[4]
1976	196,193,467	192,122,932	21,812,913	410,129,312	179,279,000[2]	589,408,312
1977	220,758,654	199,937,533	22,777,521	443,473,708	"	622,752,708
1978	220,758,654	207,752,133	23,742,129	452,252,916	"	631,531,916
1979	220,758,654	215,566,734	24,706,737	461,032,125	"	640,311,125
1980	241,583,717	223,381,334	25,671,345	490,636,396	305,083,000[1]	795,719,396
1981	309,353,795	237,062,357	27,360,085	573,776,237	430,886,000[1]	1,004,662,237
1982	345,834,147	250,743,380	29,048,824	625,626,351	"	1,056,512,351
1983	345,834,147	264,424,403	30,737,564	640,996,114	"	1,071,882,114
1984	345,834,147	278,105,426	32,426,303	656,365,876	"	1,087,251,876
1985	345,834,147	291,786,449	34,115,043	671,735,639	"	1,102,621,639
1986	345,834,147	305,007,790	35,747,041	686,588,978	"	1,117,474,978
1987	345,834,147	318,229,131	37,379,039	701,442,317	"	1,132,328,317
1988	345,834,147	331,450,472	39,011,037	716,295,656	"	1,147,181,656
1989	345,834,147	344,671,812	40,654,035	731,148,994	"	1,162,034,994
1990	450,078,723	357,893,153	42,275,033	850,246,909	779,548,000[3]	1,629,794,909

[1] Colstrip #3 and #4 based on a total cost for both of $867,206,000 in 1976 dollars, as reported by Dick Davenport of the MPCo in a phone conversation December 13, 1976. This amount was deflated by the WPI increase for Oct. 75-Oct. 76 of 3.4% to get a $838,690,000 estimate in 1975 dollars. 15% of this figure is the MPCo share of Colstrip #3, and 15% is Colstrip #4, or 125,803.6.

[2] Colstrip #2, assuming same cost as Colstrip #1 as reported FPC, Form 1, 1975, p. 432 of 92,878.7 plus AFUDC @ 16.24% of total cost.

TABLE 15 - Continued

[3]Addition of a 350 MW steam unit projected for 89-90 in the MPCo long range plan. Costs are at 857.0 $/Kw (1975 dollars) projected by the Oregon Department of Energy (see Table 4), plus AFUDC at 16.24% or $348,661,880.

[4]The 1975 figure is the year end 1975 total electric plant in service (387,308,343) reported on FPC Form 1, p. 403, plus an AFUDC allowance for Colstrip #1 at 16.24% of total cost plus 22 million to reflect the difference between the original cost valuation allowed by the FPC vs. the allowance by the PSC (based on communication with Bill Opitz).

3.4 Operation and Maintenance Expenses for Transmission and Distribution.

The historical values of transmission and distribution O & M expenses are summarized in Table 16. Distribution O & M (in constant 1975 dollars) has been quite stable at an average of 1.006 mls/kwhr. The least squares trend (regressing O & M on time) does not show statistically significant growth rate. Transmission O & M has a 10-year average value of .443, but was unaccountably higher in the middle of the recent period than at the beginning or end. Again, no statistically significant trend was derived.

Both the NWEPP study and the Oregon Department of Energy included transmission and distribution O & M in either total transmission and distribution costs or a more aggregate "non-power" cost. These were assumed constant in real terms. Based on this information, O & M expenses will be projected at 1975 levels with no escalation.

Administrative and general expense in mls/kwhr of net generation was 1.4921 in 1975. This value will be used for the projection, with no escalation.

3.5 Production Decisions

It is the assumption of this study that generating facilities will be used to the maximum of their avail-

TABLE 16

TRANSMISSION AND DISTRIBUTION: OPERATION AND MAINTENANCE EXPENSES (1975 dollars)

(A) Historical Statistic

	Transmission O & M (mls/kwhr)	Distribution O & M (mls/kwhr)
1975	.384	.969
3-year average	.428	1.016
5-year average	.4577	.9894
10-year average	.4267	.9921
OLS Trend	+1.5%	+0.2%
(Annual % Change)	(not significant)	(not significant)

(B) Assumptions for Projection

O & M (mls/kwhr)	VT = .384	VD = .969
Yearly escalation	b_{vt} = .000	b_{vd} = .000

Source: Derived FPC Form 1, 1966-1975.

ability (as reported in Table 3). It is the judgment of the Steering Committee that surplus power generated over and above the projected Montana load can be sold in the region (Appendix D). This surplus power is assumed to sell at the recent historical rates, inflated to follow changes in BPA rates (discussed in Section 4 below). Similarly, any deficiency in electrical generating resources is assumed to be covered at the recent historical average cost of purchase, again projected to follow BPA rates.

The rationale for allowing resale of surplus and purchase price of deficiency to follow BPA rates is apparent from Tables 17 and 18. As can be seen, BPA and other public authorities accounted for approximately half of all resales and for 99% of all purchases in 1975 (as derived from FPC Form 1). The average cost of purchase in 1975 was 4.729 mls/kwhr (Table 19).[1] The ten-year trend in this figure was an annual decline (in constant dollars) of 2.0%. The average revenue from resale in 1975 was 6.424 mls/kwhr. In constant dollars, this figure shows no statistically significant trend in the recent 10-year period.

The future average cost and average revenue estimates, based on the BPA rate escalation factors (dis-

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[1]Derived FPC Form 1.

TABLE 17

RELATIONSHIP OF 1975 RESALES TO LONG RANGE

PLAN RESOURCE COMMITMENTS

	(avg MW) 1975 Resales[1]	Average Revenue mls/kwhr[1]	Projected Resales[2] (avg. MW)		
			75-76	79-80	85-86
Non-Assoc. Utilities					
WWP Co.	.98	6.8	18	20	--
Utah Power & Light	39.25	7.3	30	--	--
"	2.25	4.8			
	.58	3.4			
Rural Elec. Co-ops	28.63	5.6			
Other Public Auth.					
Flathead Irrig.	11.09	1.0			
BPA	.66	7.7	--	18	18
"	2.22	6.0			
"	.34	7.9			
"	3.05	6.0			
"	19.30	10.2			
"	.17	6.9			
U.S. Bureau of Rec.	24.52	5.7			
"	.03	5.7			
Sub-Total of Other	61.41	6.3			
Total	133.12	6.4			

[1]Derived FPC Form 1, pp. 412-13.

[2]MPCo Long Range Plan.

TABLE 18

RELATIONSHIP OF 1975 PURCHASED POWER COSTS TO LONG RANGE PLAN RESOURCES

Non-MPCo Resources	(purchases) 1975 MW Average Energy	Average Cost mls/kwhr[1]	Projected Purchases[5] (avg. MW) 75-76	79-80	85-86
(A) Public					
BPA	40.0	3.2	40	20	
BPA (Hanford Extension)	13.4	9.0	49[2]	0[2]	
BPA (Hanford)	17.4	2.9	19[3]	20[3]	
BPA (Hanford Plant Restant)	29.6	5.1	26[4]	12[4]	15[4]
(B) Private					
Puget	1.0	3.6	4	0	
WWP	.25	2.7	--		
(C) Other					
WPPSS #1					68
Total	106.5[6]	4.7			

[1]Derived FPC Form 1, 1975, pp. 421, 422.

[2]This is not a contract resource according to conversation with Dick Davenport of MPCo, therefore what was purchased is far below available.

[3]Assuming entry "BPA Hanford" on FPC Form 1 corresponds to Hanford (Debt Service) on long range plan.

[4]Assumes remainder of BPA/Hanford entries may be allocated to this 1975 purchase category: BPA (Wheeling), BPA (offset), Hanford (5 mill).

[5]MPCo Long Range Plan.

[6]Does not equal sum of (A) and (B) due to exclusions of minor purchases.

TABLE 19

1975 PURCHASED POWER[1]

Utilities	kwhr	mls/kwhr	Average Energy MW
Private			
Puget Sound Power & Light	9,082,000	3.6	1.03
Washington Water Power	2,200,000	2.7	.25
Washington Water Power[2]	-	--	
Total	11,282,000	16.5	1.3
Public			
USBR	6,050,000	2.5	.7
USBR	50,000	19.0	--
BPA	350,440,000	3.2	40
BPA-Hanford	152,740,000	2.9	17.4
BPA-Hanford extension #1 & #2	117,525,000	9.0	13.4
BPA-Hanford Plant	259,193,000	5.1	27.6
Restant	885,998,000	4.5	101.1
Assoc. Nonutilities			
Colstrip test	35,672,000	3.4	
	932,952,000	4.7	106.5

[1]Derived p. 422, Account 555, FPC Form 1, 1975.

[2]Contract demand with a fixed demand charge.

cussed in Section 4 below) are shown in Table 20.

Aside from possible surplus power sales in the future, the MPCo has entered into firm contracts for purchase and delivery of wholesale power. Obviously these contracts must be included in the revenue and cost calculations. Tables 17 and 18 relate 1975 purchases and resale to those firm contracts (as derived from the MPCo long range plan [Table 1 above] and communication with company personnel).

Segments of power purchase and resale will be inflated to follow BPA rates as discussed below (part 4), lacking other information. The only exceptions to this rule will be the substantial 68 MW block of WPPSS #1 MPCo is purchasing in 1980-86. The price estimate for this facility made by the Oregon Department of Energy[1] will be used at 22.20 mls/kwhr in 1980, 20.04 in 1985, and 18.36 in 1990. The projected rates and average energy commitments are summarized in Table 21. The associated revenue and expenses are shown in Table 22.

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[1]Op. cit., p. 58 (the '85 and '90 estimates are derived from '86 and '96).

TABLE 20

FORECAST AVERAGE REVENUE FROM RESALE OF SURPLUS POWER AND PURCHASE TO COVER DEFICIENCIES 1980, 1985, 1990

(constant 1975 dollars)

	1975	1980	1985	1990
Average revenue from resale (mls/kwhr)	6.424[1]	8.456[2]	9.962[2]	10.999[2]
Average cost of purchase (mls/kwhr)	4.729[1]	6.225[2]	7.334[2]	8.097[2]

[1]Actual, based on FPC Form 1.

[2]Derived, based on BPA rate escalation factors, Table 28 and Appendix D.

TABLE 21

AVERAGE ENERGY (MW) AND RATES (MLS/KWHR) FOR CONTRACT PURCHASE AND RESALE FOR MPCo 1980, 1985, 1990 (1975 dollars)

	1975[1]	1980[2]	1985[2]	1990[2]
A. Purchased Power				
BPA				
MW average energy	40	20		
rate (mls/kwhr)	3.2	4.2[4]		
Hanford				
MW average energy	17.4	20		
rate (mls/kwhr)	2.9	3.8[4]		
BPA-Hanford				
MW average	29.6	12	15	15
rate (mls/kwhr)	5.1	6.7[4]	7.9[4]	8.7
WPPSS #1		68	68	68
MW average				
rate (mls/kwhr)		22.20[3]	20.04[3]	18.36[3]
B. Resale				
WWPCo.				
MW average energy	.98	20		
rate (mls/kwhr)	6.8	9.0[4]		
BPA & Other Public Authorities				
MW average	133.12	18	18	18
rate (mls/kwhr)	6.4	8.4[4]	9.9[4]	11.0[4]

[1]Actual based on FPC Form 1.

[2]Derived MPCo long range plan and communication with company personnel, except assumption that 1990 = 1985.

[3]Projection of Oregon Department of Energy, op. cit., p. 58.

[4]Derived using BPA rate escalation factors, Table 28.

TABLE 22

REVENUES AND KILOWATT HOURS FROM CONTRACT PURCHASES AND RESALE MPCo 1980, 1985, 1990

(1975 dollars)

	1980	1985	1990
A. Purchases - Expense			
BPA	$ 735,840		
Hanford	665,760		
BPA-Hanford	704,304	$1,038,060	$1,143,180
WPPSS #1	13,224,096	11,937,427	10,936,685
Total	15,330,000	12,975,487	12,079,865
B. Resale - Revenue			
WWPCo	$1,576,800		
BPA	1,324,512	$1,561,032	$1,734,480
Total	2,901,312	1,561,032	1,734,480
C. Purchases - Kilowatt hours (000,000)			
BPA	175.2		
Hanford	175.2		
BPA-Hanford	105.1	131.4	131.4
WPSS #1	595.7	595.7	595.7
Total	1051.2	727.1	727.1
D. Resale - Kilowatt hours (000,000)			
WWPCo	175.2		
BPA	157.7	157.7	157.7
Total	332.9	157.7	157.7

Source: Derived Table 21.

Another production parameter which must be noted is the loss due to electric company use and transmission losses. This figure is reported in FPC Form 1 as:

$$\text{loss}/(\text{loss} + \underset{\text{customer}}{\text{sales to ultimate}} + \underset{\text{resale}}{\text{sales for}})$$

For 1975 the value was 9.95%. The three-year average is 9.93% and the five-year average is 9.74%. One may conclude this is a fairly stable parameter. For projection purposes, it will be more convenient to have an estimate for

$$\text{loss}/(\text{sales to ultimate customers} + \underset{\text{resale}}{\text{sales for}})$$

If the FPC loss of 9.95% is used, by the revised definition, a 10.92% figure is derived. This will be applied to the Montana Power Company load projection to derive loss.[1]

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[1]Sales to ultimate customers and sales for resale is reported on FPC Form 1 as 5,476,000,000 kwhrs in 1975. This is very close to the MPCo load projection for 75-76 of 628 ave. MW or 5,501,000,000.

3.6 Demand

Consumption projections for electricity are of two basic types: historical trend or econometric. The former type of forecast is based on the assumption that recent historical growth rates will likely hold in the future. This type of forecast is also usually adjusted based on known future changes in consumption determinants. This is the basic approach taken by the MPCo in their long range plan; the following section is taken from that document:[1]

> V-1.2 <u>System Load and Resource Forecast for the Montana Power Company Total System</u>
>
> Load and resource forecasts are reviewed and updated frequently. These load and resource forecasts for the total Montana Power Company system are based not only on historical trends, but also are weighted in light of other factors such as anticipated additions or reductions of known loads, weather, economic conditions and many other factors. It is important to note that during the past twenty years the load projections of The Montana Power Company have been very accurate and, if anything, have under-projected load growth.
>
> The method by which The Montana Power Company forecasts its load is as follows: First, the Company separates the total load into a "base" component and a "block" component. The latter consists of a small number of large industrial users whose loads have exhibited no discernible trend over the years. Future loads for this group, both peak and average energy, are projected on a customer-by-customer basis. Future loads for the remaining component, the "base" component, are projected by means of trend extrapolation. Both peak and average energy loads are projected for this component as well as for the "block" load

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[1]MPCo Long Range Plan, pp. 13-14.

> component. Overall, Montana Power's methods of forecasting loads are similar to those traditionally employed by most other utility companies.

The Montana Power Company forecast for its system is given in Table 23.

A similar projection for the State of Montana has been developed by the Montana Energy Advisory Council.[1] The approach was to regress per capita consumption on time and heating degree days:

$$Ci/POP = C_0 + C_1\ T + C_2\ HDD$$

for residential, commercial and industrial sectors. The household and commercial equations gave good fit with R^2 of .98 and significant coefficients at the 95% level. However, the industrial equation had an R^2 of only .28. The total electrical equation also had a low R^2 of .49. Their projection of per capita consumption for 74-90 was for a 2.7% annual increase; however much of this increase was 74-75 (21.4%). The 75-90 trend was 1.42%. Combining the per capita consumption with a population projection growth rate of 1.28%, yields a 2.7% growth in electrical consumption. This result (for the entire state), is also summarized in Table 23.

The other type of projection is made by estimating the statistical relationship between the quantity de-

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[1] Energy Consumption in Montana, MEAC (August 1976), p. 14.

TABLE 23

CONSUMPTION PROJECTIONS FOR MONTANA AND THE MONTANA POWER COMPANY SYSTEM 1980, 1985, 1990
(000,000 kwhrs)

Source	1975		1980		1985		1990
MPCo for MPCo system growth rate	5,486[1]	5.61%	7,209[2]	5.07%	9,233[2]	5.07%	11,825[3]
MEAC for Montana[4]	13,154	2.49%	14,879	3.0%	17,250	2.7%	19,751
Duffield-Power[5] for Montana							
Electric Price Increase Assumption:							
1%	9,047	2.81%	10,393	1.55%	11,226	.87%	11,721
3%	8,956	1.46%	9,628	-.51%	9,387	-1.54%	8,684
5%	8,864	.09%	8,905	-2.55%	7,827	-3.91%	6,413

[1]Actual, FPC Form 1.

[2]Derived MPCo Long Range Plan.

[3]Projected.

[4]MEAC <u>Energy Consumption in Montana, Projections to 1990</u>, (August 1976), p. 14.

[5]<u>Op. cit.</u>

[6]Growth rate, 75-80.

manded and various parameters such as income (Y), price of electricity (P_e) price of a substitute, natural gas (P_g) and population (P). These equations have been estimated using OLS regression techniques for Montana as follows:[1]

$$Q_t(\text{residential}) = 4.8877\ Q_{t-1}^{.8859}\ P^{.1075}\ Y^{.0343}\ P_e^{-.1385}\ P_g^{.0238}$$

$$Q_t(\text{commercial}) = 5.9871\ Q_{t-1}^{.8735}\ P^{.1244}\ Y^{.1011}\ P_e^{-.2030}\ P_g^{.0068}$$

$$Q_t(\text{industrial}) = 4.2077\ Q_{t-1}^{.8869}\ P^{.1257}\ Y^{.0817}\ P_e^{-.2021}\ P_g^{.00}$$

Using these equations to duplicate 1967-1973 electrical consumption, without replacement of the previous year's estimate, the residential equation was off an average of only .9%, the commercial was off by 1.1%. However, the industrial was off an average of 9.3% with several years off by as much as 19%. One could conclude that this model provides a good fit on all but the industrial sector. Consumption projections using the model at increasingly higher real price escalation rates (1%/year for electrical, 3% for gas; 3% for electrical and 5% for gas; 5% electrical and 7% for gas) are shown in Table 23. The effect of higher prices actually results in a decline in future years. The projection is much lower than the other

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[1] The methodology is discussed at length in Duffield, et al., op. cit., pp. 14-24. The work relies on national estimates made in T. D. Mount, L. D. Chapman, T. J. Tyrrell, Electricity Demand in the United States: An Econometric Analysis, ORNL-NSF-EP-49, 1973.

two shown also because of the use of the Department of Commerce population projection (OBERS) which projects a decline in future years.[1]

The approach taken in this study will be to follow the MPCo projections. An algorithm for using the price-sensitive model is outlined in Appendix G; however, a simulation using that model will not be completed given the poor industrial fit and the fact that the projection is for Montana, not the MPCo system. While a price-sensitive model is generally to be preferred, the time and resources necessary to develop one applicable to this project are not available. The available price-sensitive model applies to only commercial and residential, which is only 40% of total sales in 1975.

3.7 Regulatory - Financial

The integration of revenue and cost variables in this study is based on the rate-making procedures used by the Montana Public Service Commission (Appendixes A and D). The PSC is required by law to set rates so that all costs, including a return to equity capital, are covered. The basic formulation is:

Revenue Requirement = Operating expenses + depreciation expense + fixed and variable taxes + rate of return (rate base)

or

$$RR = E(Q_G) + d + t_f + t_v + RR\ (V\text{-}D)$$

---

[1]The emphasis here is on the differing growth rates. The initial year (1975) of the projections varies due to different statistical series being used.

The revenue requirement includes revenues from contract resale, surplus sale and Montana load (discussed in 3.5). The operating expenses are the sum of the variable O & M and fuel costs outlined in 3.2 and 3.4 above.

The parameters chosen for depreciation expense, fixed tax and the variable tax rate are shown in Table 24, along with recent historical averages. The depreciation expense will be at the .02 historical share of net plant (implying a 50-year life, if a straightline method is used).[1] In fact, new generation capacity will be at a 37-year life or a .027 factor. The future historical rate will probably lie between these extremes. Sensitivity analysis has been performed on this variable as discussed in 1.3 above. The variable tax rate will be at the historical tax rate on net taxable income, .30. The most recent historic averages are somewhat variable due to adjustments to deferred taxes and investment tax credit.

The most complex aspect of regulatory proceedings is specification of the rate base. Since 1975, Montana uses an original lost depreciated base. In addition to the gross plant valuation (itemized in Tables 4 and 15 above), the state allows 100% of materials and supplies. The forecasting procedure for the latter is based on 15% of operating expenses in any given year

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[1]Projected depreciation expense is shown in Table 25.

TABLE 24

REGULATORY-FINANCIAL PARAMETERS

Variable		Projection	3 Year Average	5 Year Average
d	depreciation expense as a fraction of net plant in service V-D	.02	.01989	.02047
M&S	materials and supplies as a fraction of operating expenses	.15	.1503	.1406
t_f	taxes other than income taxes (property tax, corporate license) as a fraction of net plant	.04	.04081	.04018
a[1]	income tax, provision for deferred income tax, and investment tax credit as a fraction of net taxable income	.30	.28319	.31614

[1]All of these as recorded in FPC. Investment tax credit is added since income tax charged as shown is less the tax credit. The ratio sought here is to reflect income tax in the absence of any tax credit.

Source: Derived FPC Form 1.

TABLE 25

DEPRECIATION EXPENSE 1975-1990
(000 1975 dollars)

Year	Gross Valuation[1]	Depreciation Accumulated	Net Plant	Depreciation Expense[2]
1975	$422,286	$95,246[3]	$327,040	
1976	589,408	101,787	487,621	$6,540
1977	622,752	111,539	511,213	9,752
1978	631,531	121,764	509,767	10,224
1979	640,311	131,959	508,352	10,195
1980	795,719	142,126	653,592	10,167
1981	1,004,662	155,197	849,464	13,072
1982	1,056,512	172,186	884,325	16,989
1983	1,071,882	189,873	882,009	17,687
1984	1,087,251	207,513	879,738	17,640
1985	1,102,621	225,107	877,513	17,595
1986	1,117,474	242,658	874,816	17,550
1987	1,132,328	260,154	872,173	17,496
1988	1,147,181	277,598	869,573	17,444
1989	1,162,034	294,989	867,045	17,392
1990	1,627,794	312,330	1,317,463	17,341

[1]Table 15.

[2]At 2% of previous year net plant.

[3]FPC Form 1 shows accumulated depreciation for 1975 of 73,246,000. Twenty-two million is added here to exclude the difference in FPC and PSC OCD base from depreciation expense calculation.

(Table 24). The state also has an allowance for funds used during construction (AFUDC); this is incorporated in the gross valuation estimates outlined in 3.1 above.

The rate of return allowed by the state is based on the weighted sum of capital costs. The recent 5-year changes in capital structure and capital costs are summarized in Table 26.

The major change in capital structure has been an increase in the use of debt financing; long term debt has risen from about 46% of capital structure in 1971 to 54% in 1975. Common equity cost has fluctuated from 14 1/2% to 16%. The 1975 value was 14.74%. Long term debt has ranged from 5.29% to 7.34% (1975 was 6.33%). Preferred stock has been steady at 5.5%, but a new offering of $35 million probably at around 9% will change that ratio. To conclude, the weighted cost here fluctuates from 9.5% to 11.4%.

The most recent weighted cost we can derive, modified to account for the new preferred stock offering, is as follows:

			ratio	cost	weighted cost
preferred	21,984 +35,000	= 56,984	10.000	7.65	.765
net common	202,656		35.574	11.50	4.091
long term debt	310,027		54.422	7.176	3.905
	569,667				8.761

This tabulation suggests a weighted cost of 8.761 as the likely rate of return. The critical judgmental

TABLE 26

SUMMARY COST OF CAPITAL

	1971	1972	1973	1974	1975
Preferred Stock					
Capital ratio	8.7	8.09	7.837	5.8	4.5
Cost	5.5	5.5	5.5	5.5	5.5
Weighted cost (1)	.4769	.445	.431	.319	.248
Common Stock					
Capital ratio	45.8	45.05	47.98	41.25	41.3
Cost	15.82	16.08	16.06	14.56	14.74
Weighted cost (2)	7.246	7.244	7.706	6.006	6.09
Long-Term Debt					
Capital ratio	45.52	46.86	44.18	52.95	54.2
Cost	5.35	5.29	7.34	5.98	6.33
Weighted cost (3)	2.435	2.4789	3.243	3.1664	3.43
Total Cost of Capital					
(1)	.477	.445	.431	.319	.248
(2)	7.246	7.244	7.706	6.006	6.09
(3)	2.435	2.4789	3.243	3.1664	3.43
	10.158	10.1679	11.380	9.4914	9.768

Source: Derived FPC Form 1.

factor here is the return allowed on equity capital, which has been historically at about 15% as discussed. However, in the most recent rate order by the PSC,[1] the commission allowed 11.75% for Montana Dakota Utilities, based on a discounted cash flow and comparable earning analysis by Dr. John W. Wilson. For the current rate proceedings concerning MPCo, Dr. Wilson has developed a comparable figure of 11.50%.[2] This figure is used in the development of the 8.761 estimate. Use of the historical average allowed return on common equity would result in a 10.166 return.

For projection purposes, either of these values will increase due to interest rates on new securities being higher than the embedded cost. The Steering Committee assumption is that a 9% interest rate will hold in the future. Assuming total capital grows at about the rate of growth in consumption (5%), that the capital structure is stable, that the cumulative total of 65,500,000 debt to be retired by 1990 is refinanced at 9% and all new debt is at 9%, then a weighted cost of capital is derived for 1990 of 9.5742 (assuming 11.5% return to capital). At 15.45% return, the weighted cost is 10.979. This information is summarized in

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[1]Order No. 4245A (November 15, 1976).

[2]Docket No. 6279, Testimony of Dr. John W. Wilson.

Table 27. The intermittent years are derived by an assumption of a smooth increase in weighted costs of .0541/year.

The difficulty of actually projecting a likely rate of return or the actual rate base should be noted. The constituency of the commission periodically changes, as do the conventions for the rate making procedure. In addition, the disallowance of specific expenses in a given case is impossible to predict.

TABLE 27

PROJECTED RATE OF RETURN FOR MPCo

Cost of Common equity Assumption	1975	1980	1985	1990
11.5%	8.761	9.032	9.303	9.574
15.45%	10.166	10.437	10.708	10.979

Source: Derived from Appendix D, Recent PSC Rate Orders, FPC Form 1, and Testimony of Dr. John W. Wilson before the Montana Public Service Commission.

4. BPA RATES

One of the major simplifications of this study has been to examine a utility system, the Montana Power Company, as though it were a separate entity. In fact, the business of producing and delivering electricity is performed by a closely integrated regional network. Attempting to actually simulate this complex system is far beyond the resources of this study. As an approximation, we have assumed that in its wholesale dealings with the regional system, Montana Power will face costs and revenues dominated by the BPA rate structure. (as discussed in Section 3.5 above).

The purpose of this section is to summarize our conclusions as to changes in BPA rates. The analysis is shown in Table 28. A set of factors was derived for inflating 1975 rates to future rate levels. The basic information used was that BPA will increase rates by 60% in 1979 and 20% in 1981.[1] These increases were deflated by 5% per year to derive increases in constant 1975 dollars. (That is, the increases include a 5% yearly inflation rate.) Beyond 1981, rates are assumed to escalate in real terms at 2% per year.[2]

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[1]Communication with Mr. Gordon Brandenburger, BPA District Manager in Kalispell.

[2]Oregon Department of Energy, op. cit.

TABLE 28

BPA RATE ESCALATION
(Constant 1975 dollars)

(A) Use of Factors:

(1975 rate) x (factor for year t) = rate for year t

(B) Factors:

Year	Factor
1975-1978	1.0000
1979-1980	1.3163[1]
1981	1.4327[2]
1981 + t	[3] $1.4327\ (1.02)^t$
(1985)	(1.5508)
(1990)	(1.7122)

[1]Reflects a 60% rate increase in 1979, deflated by BPA inflation assumption of 5%/year (Appendix D).

[2]Reflects a 20% rate increase in 1981, deflated by BPA inflation assumption (Appendix D).

[3]Reflects a 2% increase in real value beyond 1981, based on Oregon Department of Energy estimates.

A P P E N D I C E S

APPENDIX A

Letter to Bill Opitz Concerning the Regulatory Model

University of Montana
Missoula, Montana 59801
(406) 243-0211

December 2, 1976
Department of Economics

Mr. William Opitz
Administrator, Utility Division
Public Service Commission
1227 Eleventh Avenue
Helena, Montana 59601

Dear Bill:

Thanks for returning my call this morning; the information was much appreciated.

I am writing mainly to summarize my understanding of the current Public Service Commission's conventions on establishing electric utility rates (as derived from rate orders and our conversations). This is in order to give myself a written record, and to give you an opportunity to correct any misunderstandings on my part.

There is one point on which I cannot quite reconcile our conservations with the recent M.D.U. rate order: in that order (finding #15) the order notes that "Applicant is compensated ... through AFUDC". However, I had understood that no portion of C.W.I.P. (except "in service") is capitalized by the P.S.C.

Thanks again for your assistance.

Sincerely,

John W. Duffield

John W. Duffield

SUMMARY OF MAJOR RATE REGULATION CONVENTIONS in use by the MONTANA P.S.C.

(1) Rate Base

Montana's rates (as of January 1, 1975) are on an original cost depreciated basis. The actual OCD estimate accepted by the P.S.C. is approximately $22 million higher than the net electric plant valuation listed in pulbished F.P. C. statistics (for any given year). (Due to a historic difference not resolved in a joint commission hearing in 1945.)

I will assume that 100% of materials and supplies (including fuel stocks) can be incorporated in the rate base. No allowance is assumed for working capital or for constuction work in progress (except C.W.I.P. "in service") or funds used during construction.

The rate base is calculated on an average rather than year-end basis. Accumulated investment tax credits will be subtracted from the rate base.

(2) Rate of Return

The rate of return is, of course, based on the sum of weighted capital costs. Costs of preferred stock and long term debt components are based on actual costs to the company rather than just the coupon rate. It appears from the most recent M.D.U. order (no. 4245A) dated November 15, 1976, that the return on common equity allowed will be based on both comparable earnings and a discounted cash flow analysis.

Short term debt will not be used in establishing capital structure or costs.

An apparently unresolved issue is whether the debt held by the MPCo's Western Energy subsidiary should be included in capital structure. For the present, I will assume that it is not.

(3) Net Income

Net income will in general correspond to the F.P.C. statistic entitled "electric utility operating income", (which is operating revenues net of taxes, operating expenses, and depreciation expenses).

There will obviously be adjustments to this figure for any given test year depending on specific expenses, such as institutions (and promotional advertising) disallowed.

Income and expense estimates are year long figures, rather than beginning - end of year averages.

(4) Rate Structure

For the present, I will assume that no changes will be made in the rate structure. However, rate increases will be allocated to consuming sectors on a constant cents per kilowatt hour basis rather than as constant percentage increases. (Other things constant, this will, of course, gradually change the historic revenue shares contributed by each consuming sector (residential, commercial, industrial).)

Note to letter December 2, 1976:

As corrected during a conversation with Bill Opitz on December 6, 1976, the Public Service Commission does make an allowance for funds used during construction--AFUDC. This is an allowance for interest charged on funds used to cover construction costs. A typical approach is to allow 9% of the construction costs to be added to the rate base <u>after</u> plants begin operation. The MPCo estimate of 1,008,000,000 for Colstrip #3 and #4 include AFUDC and is 16.24% of the total (phone conversation with Dick Davenport of MPCo on December 7).

APPENDIX B

Letter to Don Gregg

University of Montana
Missoula, Montana 59801
(406) 243-0211

December 2, 1976
Department of Economics

Mr. Don Gregg
Montana Power Company
40 East Broadway
Butte, Montana 59701

Dear Mr. Gregg:

I have been asked by the State Department of Administration to project electrical rates to the year 1990. As I understand Phil Hauck, the State Architect, the information will be used for life cycle costing in the design of State buildings and heating systems. I have enclosed a copy of my contract and a (very abstract) work proposal for your further information. As you can see by the size of the budget, this is not a long-term study. I am hoping to have preliminary numbers by late December.

Obviously I will be needing specific information on future generation, transmission and distribution capacity and operation and maintenance costs. Some of this is available through the long term plans MPCo has filed with the Public Service Commission. Other information is publicly available, but dated. I would appreciate your assistance in getting the most current estimates the company is using. However, I am not expecting you to develop special information for the benefit of this project. If you have the numbers, that would be very helpful, if not I will trend historical data or use parameters suggested in other regional and national studies of the utility industry.

To this purpose, I spoke with Dick Davenport of your office yesterday (since you were out). Dick was able to supply me with many of the parameters I needed. I thought it would be wise to summarize the information I received so we would both have a written record and so any misunderstanding on my part would be corrected. I also have a few additional requests. A summary of this information follows:

(1) Future Generating Capacity and Costs.

Dick gave me a total cost figure of $1,008,000,000 for Colstrip #3 and #4. It would be useful to know if there is a specific inflation (as opposed to a real cost) adjustment in these numbers, and if so - at what rate.

I will assume that construction costs will be distributed over the construction period evenly. (This is relevant should the P.S.C. allow capitalization of C.W.I.P. in the rate base.)

I have a copy of the most recent long range plans for 1975-1976 to 1985-1986, filed with the P.S.C. I will use this schedule for generating capacity coming on line (except as Dick corrected specific dates of operation to October 1980 for #3 (#4 remains at August, 1981)). Beyond '85-86, it is mentioned in the plan that an additional 350 MW steam or the Buffalo Rapids hydro is a possibility. It would be useful to have your best guess on capacity additions in the '86-96 period. (Dick suggested he would send the information.) Any wild guess on $/kw capacity in that period?

Do you anticipate any changes in installed hydro capacity in this period?

(2) Future Generation Operation and Maintenance Expenses.

Dick gave me an O.&M. expense estimate on #3 and #4 of 1.42mls/kwhr. Do you have a number for Colstrip #2 (otherwise I will assume it is what #2 did in the '75 data I have)? Do you have a guess on escalation of O&M beyond '80-81?

For a capacity factor for the first full year of #3 & #4 operation, Dick suggested 70% and 75% thereafter.

Regarding fuel costs, Dick gave me a #3 and #4 heat ratio of 10,819 BTU/kwhr. What is the expectation on #1 and #2? Coal in 1980-81 is estimated to be $10.00/ton. I was curious to know what would determine this price given that Western Energy is a subsidiary; Dick suggested it would be a market price for the region. What do you expect to be the BTU/lb. of future coal? Any wild guesses on fuel costs in 1980-90 period? In the event that oil or gas is available for the Frank Bird plant, what is your guess on price?

(3) Transmission and Distribution Capacity.

It would be very helpful to have your best guess on total transmission and distribution capacity additions by year to 1990, since this is a very substantial portion of the rate base. If this is not readily available I will project historic relations between generating capacity and transmission and distribution.

As an index to capital cost increases in this area, it would be useful to have your estimate on transmission costs associated with the Colstip #3 and #4 project. The most recent number I can find on public record is an estimate of $214,688,000 cited by William Bellingham before the D.N.R. in March of this year.

(4) Transmission and Distribution O & M.

Dick suggested that if one had the capital costs of new transmission and distribution, O&M expenses will be .008 or 8/10 of 1% of the capital costs. Do you have an estimate of the likely escalation rate of O&M on the existing system for '75-90?

(5) Consumption or Load Projection.

As I understand Dick, the "Energy Load" figure cited in the long range plan by year is net generation. Therefore, consumption (or sales) is of course this net generation figure less transmission loss (historically 10%-11%). (For example, in the "average energy" table, "energy load" for '75-76 is 628 MW, therefore, net generation is 628 mw X 1000 kw/mw X 8760 hrs/year = 5,501 million kwhrs/year. This would include energy received from other sources as well.)

I will probably be using the companies' consumption projections. I just have these to '85-86; it would be useful to have this to '90. (Dick indicated he would send this - otherwise I would just extrapolate the trend.) It would be nice to have a price-sensitive projection, but the available econometric studies relating to Montana seem unreliable.

(6) Production Decisions.

In order to simulate generation costs, I will need to assume a priority ordering for use of existing plants. I will assume that hydro will be used at a maximum subject to maintenance and water conditions. Do you see any reason for not using the most recent ten year average of hydro generation in the MPCo system as the basis for most likely future generation?

I will also assume that the Corette plant will be available at its recent historic capacity factor, and that Colstrip #1, #2, #3, and #4 when on line will be used at 75%. Does this seem the best assumption?

When these assumptions of the available base resources are compared to the load projections for the '76-86 period, there are surpluses of varying magnitudes in most years and deficiencies in '79-80 and '85-86. This leads to three basic cases: surplus periods, periods of energy coal equaling base resources, and periods of deficiency.

For the periods of surplus, I am unsure as to whether the surplus will be generated and sold for resale or whether generations will be cut back to just meet the estimated (and, hopefully, actual) load. Dick suggests this will depend on market conditions; i.e., can the costs of that generation be recovered at the existing resale prices. This leads to two specific questions: (1) What is your best guess as to the likely average rates MPCo will face for surplus power by year to 1990? (Lacking your best guess, I will be using historic average revenue figures for sale for resale with some escalation factor related to the factor derived for Montana rates. Incidently, who would you expect to be buying this power? B.P.A.? West Group utilities?), (2) May I assume that generation will occur if the resale rate is equal or greater than variable costs? (The standard economic theory here is, of course, that production should occur as long as revenue is covering or more than covering variable costs and therefore, contributing toward fixed costs.)

For periods of deficiency, in the absence of better information, I will assume that purchases will occur when this is cheaper than running the Frank Bird plant. If power is not available elsewhere or is too expensive, and given availability of gas and oil, I will assume that the Frank Bird plant will be used. Specific question: what is your best guess on price and availability of power for purchase by year to 1990? (Obviously this depends on market conditions in the region plus B.P.A. policy plus cost escalation faced by other public and private producers. In the absence of a best guess I will escalate the recent historic average purchase price.)

The final basic case under my set of assumptions concerns situations where average load is equal or nearly equal to median available generation resources. In such cases there may, of course, still be a need for purchase and resale due to the shape of the load curve faced by the company (i.e., peak demand at times will exceed available resources). I would expect that in reality the true base load resources will be the steam system, and that there will be some use of hydro for peaking or cycling subject to water availability. Is this true? Rather than attempt a more realistic simulation of this complex system (which is beyond the resources available for this study), I will rely on historical operating data to fix likely levels of purchase and resale as a percent of MPCo system net generation. This type of relationship, which assumes that much of historic purchase and resale is for load leveling (rather than actual average systems generating capacity deficiency) seem born out by the fact that purchases and resales tend to be of the same approximate magnitude (example: in 1974 purchases were 1,204,592 kwhrs. and sales for resale were 873,636). I would be curious as to your evaluation of this approximation.

An alternative assumption is that MPCo is trading in the wholesale market for electricity in the same way that speculators trade for soybean futures; this seems unreasonable.

(7) Regulatory and Financial Parameters.

The final area of my study concerns the rate making procedures used by the Public Service Commission. The best source on this problem is the P.S.C. itself. However, it would be useful to have the company's best guess on what future regulatory policy will be - given that 15 years hence the constituency of the P.S.C. will undoubtedly have changed. Dick Davenport suggested I speak with Jack Burke on this matter; I am hoping to speak with him by phone in the near future. For economy of organization, I will list below my basic questions in this area and send a duplicate of this letter to Mr. Burke. I will note that I am not asking what regulatory policy should be, but for your best crystal-ball version of what it will be.

(a) Rate Base

Current policy appears to be an original cost depreciated base plus 100% allowance for materials and supplies (including fuel stocks), no allowance for working capital, and no allowance for construction work in progress (except CWIP "in service"). Does the company anticipate changes in these conventions?

(b) Rate of Return

Does the company anticipate a fairly stable capital structure? That is, will recent historic shares of capital derived from common equity, long term debt, and preferred stock be approximately maintained? Does the company visualize constraints on capital structure (i.e., long term debt shall not exceed 60% ?). What is your best guess on the marginal cost of future debt offerings (i.e., what is your guess as to the interest rate the company will face on long term bonds and debenture?). If you anticipated future preferred stock offerings, what would the coupon rate probably be? What is your guess as to the allowed return on common equity in future P.S.C. proceedings?

(c) Net Income

Do you anticipate any changes in allowed operating expenses or in the treatment of tax and depreciation expenses?

(d) Rate Structure

I am assuming there will be "no changes" in the rate structure. Do you have a comment on this issue?

This concludes my questions on this matter. I appreciate the assistance I was given by Dick Davenport, and look forward to receiving your response on these other points.

Sincerely,

John W. Duffield

John W. Duffield

APPENDIX C

Steering Committee

MONTANA ENERGY ADVISORY COUNCIL
STATE CAPITOL
HELENA, MT 59601

BILL CH[illegible] [illegible]N, CHAIRMAN

December [illegible], 1976

MEMORANDUM

TO: Dr. Richard Stroup
Dr. John Duffield
Mr. Roger Billings
Dr. Sid Groff
Dr. MacGregor Rugheimer
Mr. Alex Drapes
Mr. Dick Bourke
Mr. John McBride
Mr. Andy Kissner
Mr. Geoffery Brazier
Mr. Gordon Bollinger
Mr. Gene Huntington
Mr. Phil Hauck
Mr. Bill Opitz
Mr. Gordon Brandenburger
Mr. Ed Spear
Senator Frank Hazelbaker

FROM: James H. Nybo, Energy Research Coordinator J.H.N.

RE: Future Natural Gas and Electric Prices in Montana

This is to confirm a meeting on Monday, December 6, 1976, of an informal steering committee for a study of future natural gas and electric prices in Montana. The study is being performed by Dr. Richard Stroup and Dr. John Duffield under contract to the Montana Department of Administration with assistance by the Montana Energy Advisory Council staff. The purpose of this meeting will be to discuss the major variables which will determine future energy prices in the state, and to advise the contractors as to the most reasonable assumptions which can be made concerning energy supply, demand, and rate structure in Montana.

The meeting will be held in Room 436 of the State Capitol Building in Helena, beginning at 1:30 p.m. on December 6, 1976.

I apologize for the extremely short notice, but I sincerely hope that you, or an alternate representative, can attend.

JN/tw/mt

Individuals attending the December 6 meeting:

Dr. Richard Stroup, MSU
Dr. John Duffield, U of M
Dr. Sid Groff, State Geologist
Dr. MacGregor Rugheimer, MSU
Mr. Alex Drapes, Drapes Engineering
Mr. Greg Conniff, Drapes Engineering
Mr. Dick Bourke, Environmental Quality Council
Mr. Bill Headapohl, MPC District Manager
Mr. Geoffery Brazier, Consumer Council
Mr. Gene Huntington, Office of Budget and Program Planning
Mr. Phil Hauck, State Architect
Mr. Bill Opitz, PSC Utility Staff
Mr. Gordon Brandenburger, BPA (Kalispell)
Mr. Newell Anderson, Montana Trade Commission
Mr. James H. Nybo, MEAC

APPENDIX D

Steering Committee Assumptions

SUMMARY OF ELECTRIC RATE PROJECTION STUDY ASSUMPTIONS
BASED ON STEERING COMMITTEE MEETING,
HELENA, DECEMBER 6

1. Future Generating Capacity and Costs:

   (a) Future generating capacity is assumed to come on line as specified in the MPCo long range plan. This includes the Colstrip #3 and #4 plants and a 350 MW steam unit on line in 89-90.

   (b) Generation capacity costs for #3 and #4 are as projected by MPCo, with an adjustment for assumed inflation. This trend will be used to project costs of the future 350 MW unit or use national estimates for the future 350 MW.

2. Generating Operation and Maintenance Costs

   (a) Existing plant O & M will be based on trended historical data.

   (b) New plant O & M as reported by MPCo as available, or

   (b)[1] Trended historical or national estimates.

   (c) Coal is assumed to sell for $10/ton in 1980; other years derived based on this trend.

   (d) Heat rates on existing plants based on historical, new or MPCo estimates.

3. Transmission and Distribution Capacity
   (a) Based on MPCo estimates as available or
   (a)[1] Historical relationship of transmission capacity to generation capacity and distribution to net generation.
4. Transmission and Distribution O & M Expenses
   (a) MPCo estimates as available or
   (a)[1] trended historical data.

5. Demand Projection
   (a) Commercial and residential sectors based on national elasticities as estimated by Chapman et al. adjusted for a Montana-specific intercept. The constant elasticity, OLS model will be used. Industrial will be based on MPCo estimates, as available, or
   (a)[1] Use aggregate MPCo estimate of Montana load as specified in the long range plan.
   (b) All surplus power can be sold. The resale and purchase rates will be projected at some multiple of BPA wholesale rates based on most recent data. BPA rates will be at the current levels through 1978; in 1979 prices will increase by 60%; in 1981 prices will increase by 20%. Beyond this period the 76-81 2% real price increase is assumed.

6. Production Decisions
   (a) Hydro will be available at the recent 10-year average.

(b) Corette plant will be used at recent historic capacity.

(c) Colstrip plants operated at recent historic capacity for Corette.

(d) For periods of deficit, power will be available at BPA rates specified under 5(b) above. Power will be purchased if costs are less than projected variable cost of operating the Frank Bird plant.

7. Regulatory and Financial Parameters

(a) Current PSC conventions with regard to rate base calculation are assumed to hold in the future: original cost depreciated, 100% materials and supplies, no working capital, AFUDC included after plant is in operation, and no CWIP allowance. Given the uncertainty of future investment tax credit, no allowance will be made.

(b) The current capital structure will be assumed to hold in the future. Common equity returns and preferred stock returns will be at the most recent level. The embedded cost of long-term debt will reflect an assumed long-term interest rate on all future debt offerings of 9%.

(c) Net income will be based on the FPC definition of "net utility operating income." Depreciation expense for new plants will be based on the straight-line method and a 37-year life. Depreciation

expense on net utility plant excluding new generation capacity (but including new transmission and distribution) will be at the recent historic average. Property taxes will be at the recent historic share of new plant; income taxes will be based on the historic rate on net utility operating income.

(d) There will be no changes in the rate structure. It is assumed that historic average revenue relationships approximate historic average cost relationships by sector (residential, commercial, industrial). Future rate increases will be allocated so as to maintain this historic relationship. Within a sector, steps in the declining block structure will be increased by equal absolute amounts (e.g., 3 mls/kwhr) rather than by equal percent increases (e.g., .3%).

APPENDIX E

Simulation Variables Defined

VARIABLES FOR SIMULATION

Note: all variables are also subscript t.

Q_G = generation projected--<u>given</u> by MPCo.

Q_M = energy load in Montana projected by MPCo.

Q_S = surplus (deficit) generation over energy load for resale.

= $Q_G - Q_M - L$

L = transmission and distribution loss = 1 (Q_M)

Q_I = Montana industrial load <u>given</u>

Q_R = Montana residential = f (AR_R. . .)

Q_C = Montana commercial = f (AR_C . . .)

AR_M = average revenue on Montana load

AR_S = average revenue on resale load

AR_I = average revenue on Montana industrial load

AR_R = average revenue on Montana residential load

AR_C = average revenue on Montana commercial load

AI_R = historic ratio of industrial average revenue to residential average revenue

AC_R = historic ratio of commercial average revenue to residential average revenue

Q_{ki} = contract resale, source i

AR_{ki} = contract resale average revenue, source i

Q_{pj} = contract purchase, source i

AC_{pj} = contract purchase, average cost.

$E(Q_G)$ = operating expenses

d = depreciation expenses

t_f = fixed taxes

t_v = variable taxes

V = gross valuation

ms = materials and supplies

D = accumulated depreciation

RR = rate of return

a = marginal tax rate for variable taxes

l = transmission and distribution loss as a fraction of energy load Q_M

$(O\&M)_{ti}$ = operation and maintenance costs, source i, year t

Q_{Gi} = generation, source i = (load factor) (8760) (capacity)

Q_{Gt} = ΣQ_{Gi} sources in operation year t

FC_{ti} = fuel costs, source i

$b_{(O\&M)i}$ = escalation rate O & M, source i

$b_{(FC)i}$ = escalation rate O & M, source i

$O\&M_{1975,i}$ = O & M 1975, source i

$FC_{1975,i}$ = fuel costs, 1975, source i

AG_t = administration and general expense, year t

b_{AG} = escalation rate of administration and general expense

b_{VT} = escalation rate of real costs of transmission O & M

VD_t = O & M of distribution, year t

b_{VD} = escalation rate of real costs of distribution O & M

TS_t = addition to transmission system, year t

DS_t = addition to distribution system, year t

GS_t = addition to generation system, year t

PS_t = addition to general plant, year t

D_t = accumulated depreciation

V_{1975} = gross valuation in 1975

RR_{1975} = allowed rate of return in 1975 = 8.761 (or 10.166)

rr = yearly increment to RR = .0541

APPENDIX F

Algorithm for Input Variable Estimation

ALGORITHM FOR DEFINING YEARLY SIMULATION VARIABLES

$E(Q_{Gt}) = VT_t \cdot Q_{Gt} + VD_t \cdot Q_{Gt}$

$\qquad \sum (O\&M)_{ti} \cdot Q_{Gi} + \sum FC_{ti} \cdot Q_{Gi} + AG_t \cdot Q_{Gt}$

$O\&M_{ti} = (O\&M_{1975,i}) \quad (1 + b_{(O\&M)i})^t$

$FC_{ti} = (FC_{1975,i}) \quad (1 + b_{FC,i})^t$

$VT_t = VT_{1975} \ (1 + b_{VT})^t$

$VD_t = VD_{1975}(1 + b_{VD})^t$

TS_t = transmission system in year t

= f_1 (net generation)

DS_t = distribution system in year t

= f_2 (# customers)

customers = f_3 (Montana population)

PS_t = general plant in year t

= f_4 (# customers)

GS_t = generation system in year t

= $(\text{kilowatt capacity})_{\text{plant } i} \quad (\text{R/Kw plant } i)$

V_t = gross valuation

$= V_{1975} + \sum_{i=1}^{t} \quad TS_t + DS_t + GS_t + PS_t$

d_t = depreciation expense

$= .02 \ (V_{t-1} - D_{t-1})$

D_t = accumulated depreciation

$= \sum_{i=1}^{t} \quad d_t + D_{1975}$

$D_{1975} = 73{,}246{,}451$

MS_t = materials and supplies year t

= .15 (operating expenses) year t-1

t_{tf} = fixed taxes in year t

= $.04\ [V_t - D_t]$

RR_t = rate of return on capital in year t

= $RR_{1975} + (t-1975)\ (rr)$

a = marginal tax rate = .30

APPENDIX G

Price-Sensitive Model

PRICE SENSITIVE ALGORITHM

A. Derivation of $Q_R = f\ (AR_R \ldots)$; $Q_C = g\ (AR_C \ldots)$

1. Given the following equations:

   Residential Demand $Q_{Rt} = Q_{Rt-1}^{.8859}\ P_e^{-.1385}\ K_t$

   Commercial Demand $Q_{Ct} = Q_{Ct-1}^{.8859}\ P_e^{-.2030}\ K_t$

2. Given the MPCo total consumption projections by year, take 20.85% to get the residential share and 18.17% to get commercial (based on 1975--36.93% is industrial, 2.77% other, and resale 21.25%).

3. Assume that the MPCo projections imply constant real prices at 1975 levels (21.94 AR commercial in 1975, and 24.05 AR residential in 1975). Using this assumption solve for K_t in each year.

4. These equations can now be used in the following algorithm to solve equilibrium price and quantity sequentially for each year.

EQUATIONS FOR SIMULATION: PRICE SENSITIVE CASE

B. Demand Side

1. $\dfrac{AR_I}{AR_R} = A_{IR}$ 1975 average revenue relationship

2. $\dfrac{AR_C}{AR_R} = A_{CR}$ 1975 average revenue relationship

3. $AR_M = \dfrac{AR_I\ .Q_I + AR_R\ .Q_R + AR_C\ .Q_L}{Q_M}$

Montana load equals average revenue for weighted average of consuming sectors

4. $Q_R = f\ (AR_R \ldots)$	residential demand function
5. $Q_t = g\ (AR_C \ldots)$	commercial sector demand function
6. $Q_M = Q_R + Q_C + Q_I$	sum of sectors equals Montana load
7. $Q_G = Q_S + Q_M + L$	generation equals resale and Montana load plus loss
8. $L = 1Q_M$	loss is a fraction of Q_M

C. Regulatory Constraint/Supply

9. $Q_S.AR_S + Q_M.AR_M = E(Q_G) + d + t_f + t_v + RR\ (V-D)$

10. $t_v = a\ [AR_S.Q_S + AR_M.Q_M - E(Q_G) - d - t_f$ income tax as a function of net revenue]

PRICE ELASTIC CASE--SOLUTION ALGORITHM

D. Solution Algorithm

Equations 1 through 6 can be solved for Q_M and AR_M as a function of AR_R by substitution of various AR_R values, corresponding AR_M, Q_M (price, quantity) pairs are derived which define the price sensitive demand curve for the Montana load.

By equations 7 and 8:

11. $Q_S = Q_6 - (1 + \ell)\ Q_M$

given an AR_M and a Q_M, Q_S is derived.

By equations 9 and 10, in equilibrium:

12. $Q_S.AR_S + Q_M.AR_M = E(Q_6) + d + t_f + RR\ (V-D) + a$

$$[AR_S.Q_S + AR_M.Q_M - E(Q) - d - t_f]$$

Equation 12 states that total revenue equals total costs.

For any given year the following solution steps may be followed:

1. Substitute previous year AR_R into equations derived from (1-6) to derive corresponding AR_M and Q_M.
2. Solve for correspond Q_S by equation 11.
3. Compare total revenue ([$Q_S.AR_S + Q_M.AR_M$] [note AR_S is <u>given</u> for any year]) with total cost (the right side of equation 12). Given rising costs total revenue will likely be less than total cost. If TR TC, substitute a slightly higher AR_R and repeat 1 through 3 until TR = TC.

   (Note: In the short run, price elasticity of Q_M will be on the order of -.13, therefore an increase in AR_R and therefore AR_M will <u>increase total revenue due to Montana sales</u>. In addition, as AR_M rises, Q_M falls and given fixed generation Q_G (by equation 11) Q_S rises AR_S is fixed. Therefore as AR_R rises, $AR_S.Q_S$ or the <u>total revenue from resale</u> also rises.)

APPENDIX H

ALGORITHM FOR CALCULATING AVERAGE REVENUE

1. $Q_S = Q_G - L - Q_M + \sum Q_{Pj} - \sum Q_{Ki}$

2. $WA = -Q_S^{*} . AR_S - \sum AR_{Ki} . Q_{Ki} + \sum AC_{Pj} . Q_{Pj}$

WA = wholesale account

3. $$AR_M = \frac{WA + E\ (Q_G) + d + t_f + (\frac{RR}{1-a})\ (V-D + MS)}{Q_M}$$

*if the value of Q_S is negative (i.e., deficit rather than surplus), then $AR_S = AC_P$